UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# Form 10-K

[ X ] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
**For the fiscal year ended December 31, 2000**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.

**Commission File Number 1-12480**

# LOUIS DREYFUS NATURAL GAS CORP.

(Exact name of Registrant as specified in its charter)

| | |
|---|---|
| **Oklahoma** | **73-1098614** |
| (State or other jurisdiction of incorporation or organization) | (IRS Employer Identification No.) |
| **14000 Quail Springs Parkway, Suite 600 Oklahoma City, Oklahoma** | **73134** |
| (Address of principal executive office) | (Zip code) |

Registrant's telephone number, including area code: **(405) 749-1300**

Securities registered pursuant to Section 12 (b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| **Common Stock, par value $.01 per share** | **New York Stock Exchange** |
| **9¼% Senior Subordinated Notes due 2004** | **New York Stock Exchange** |

Securities registered pursuant to Section 12 (g) of the Act:

**None**

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES X NO _.

Indicate by check mark if disclosure of delinquent files pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ X ]

The aggregate market value of the voting stock held by non-affiliates of the Registrant at February 22, 2001, was approximately $894 million (based on a value of $36.75 per share, the closing price of the Common Stock as quoted by the New York Stock Exchange on such date). 43,877,479 shares of Common Stock, par value $.01 per share, were outstanding on February 22, 2001.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the definitive proxy statement for the Registrant's 2001 Annual Meeting of Shareholders, to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference into Part III.

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# LOUIS DREYFUS NATURAL GAS CORP.

## PART I

### Item 1 -- BUSINESS

**General**

Louis Dreyfus Natural Gas Corp. is one of the largest independent natural gas companies in the United States engaged in the acquisition, development, exploration, production and marketing of natural gas and crude oil. Our acquisition, development and exploration activities are primarily conducted in three geographically concentrated core areas: the Permian Region which includes west Texas, southeast New Mexico and the San Juan Basin; the Mid-Continent Region which includes Oklahoma, Kansas, the panhandle of Texas, east Texas, southwest Arkansas and north Louisiana; and the Gulf Coast Region, which includes south Texas and offshore Gulf of Mexico. Our proved reserves as of December 31, 2000 totaled 1.8 Tcfe and future net revenues from these reserves had a discounted present value of $3.7 billion. Properties that we operate contain approximately 79% of our total proved reserves. Natural gas reserves comprised 89% of our year-end proved reserve position and 82% of our reserves were proved developed. The average reserve life of our proved reserves was 13.2 years. The definitions of certain technical terms can be found beginning at page 11.

Louis Dreyfus Natural Gas Corp. originated with the acquisition of 61 Bcfe by S.A. Louis Dreyfus et Cie in 1990. Since that date, we have experienced significant growth in production and proved reserves through both development and exploration drilling and proved reserve acquisitions. We have accumulated interests in 2.8 million gross acres with 2,124 identified drilling locations as of December 31, 2000. Of these locations, 770 had been assigned proved undeveloped reserves at December 31, 2000. We aggressively exploit the value in our properties through an active development drilling program. This program has resulted in the drilling of 1,689 wells with a completion success rate of 92% over the five-year period ended December 31, 2000. In recent years, exploratory drilling has been increasingly emphasized as an integral component of our business strategy and, consequently, we have incurred substantial up-front costs, including significant acreage, seismic and other geological and geophysical costs. During 2000, we invested $39 million in connection with exploration activities, $22 million of which was directed to acreage and seismic acquisition. Our exploration program has had a cumulative drilling success rate of 70% over the five-year period ended December 31, 2000.

We have replaced 282% of our production since 1995 at an average finding cost of $1.01 per Mcfe, including the purchase accounting impact of acquiring American Exploration Company in 1997. Finding costs excluding the effects of the American Exploration acquisition, which we believe are more representative of our historical ability to replace reserves, were $.85 per Mcfe over this same five-year period. The following table reflects our growth since 1995:

**SELECTED GROWTH STATISTICS**

| | Years Ended December 31, | | | | | Five-year Growth |
|---|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 | 1997 | 1996 | Rate |
| Production (Bcfe) | 137.0 | 125.8 | 121.6 | 84.3 | 75.0 | 17.4% |
| Proved reserves (Bcfe) | 1,808.0 | 1,464.3 | 1,340.2 | 1,203.4 | 990.2 | 15.6 |
| EBITDAX (MM$) (1) | $ 381.8 | $ 213.0 | $ 183.8 | $ 164.9 | $ 128.6 | 27.9 |
| Net cash provided by operating activities (MM$) | $ 278.0 | $ 181.6 | $ 147.4 | $ 129.8 | $ 101.8 | 25.4 |
| Net income (loss) (MM$) (2) | $ 98.3 | $ 21.4 | $ (43.3) | $ (16.1) | $ 21.1 | 54.9 |

(1) - See "-- Certain Definitions."

(2) - Earnings for 1998 were adversely affected by a $52.5 million non-cash impairment charge and a significant decline in oil and gas prices. Earnings for 1997 were adversely affected by a $75.2 million non-cash impairment charge, substantially all of which was recognized in connection with the American Exploration acquisition. Earnings for 2000 were positively influenced by higher oil and gas prices and higher gas production. See "Item 7 -- Management's Discussion and Analysis of Financial Condition and Results of Operations."

The address of our principal executive offices is 14000 Quail Springs Parkway, Suite 600, Oklahoma City, Oklahoma 73134, and our telephone number is (405) 749-1300.

**Business Strategy**

Our business strategy is to generate strong and consistent growth in reserves, production, operating cash flows and earnings. This strategy is implemented through the following:

*Natural Gas Focus.* We emphasize growth in natural gas reserves and believe that the long-term supply and demand fundamentals for natural gas are favorable for continued strength in natural gas prices. Natural gas continues to gain recognition as an efficient, clean and environmentally-friendly fuel source alternative. This is particularly true for electricity generation facilities, which are increasingly turning to natural gas for their power consumption needs. About 89% of our reserve base is comprised of natural gas, making us substantially more leveraged to natural gas than the industry average. Because of this focus, we now have one of the largest domestic natural gas reserve bases in the industry.

*Expanded Exploration Program.* Increased exploration activity in our core areas exposes us to higher production and reserve growth potential. We have a staff of 29 geoscientists and reservoir engineers who have extensive experience in the use of advanced technologies, including 3-D seismic analysis, computerized mapping and reservoir simulation modeling. These technologies are combined with a considerable knowledge base gained through our operating and development drilling activities in these core areas. The combination results in a disciplined approach to exploration growth. During 2000, $39 million was invested in connection with exploration activities, including drilling, seismic data collection and unproved leasehold acquisitions. Over the five-year period ended December 31, 2000, we have drilled 125 gross (78 net) exploratory wells with a completion success rate of 70%. We have allocated approximately $64 million, or 22%, of our 2001 drilling budget to exploration activities.

*Development Drilling.* We aggressively exploit the value in our oil and gas property base through an active development drilling program. The development drilling program has been an important source of low-risk production growth and is conducted in areas where multiple productive oil and gas bearing formations are likely to be encountered, thereby reducing dry hole risk. We have drilled 1,564 gross (1,045 net) development wells with a completion success rate of 94% over the five-year period ended December 31, 2000. For 2001, we plan to continue our aggressive development drilling program by investing approximately $226 million, or 78% of our 2001 drilling budget.

*Strategic Acquisitions.* We have invested $594 million to acquire 562 Bcfe of proved reserves over the five-year period ended December 31, 2000, representing an average acquisition cost of $1.06 per Mcfe. We believe that this aggregate average acquisition cost, which includes the purchase accounting impact of the American Exploration acquisition in 1997, compares favorably to industry averages for independent exploration and production companies over this same period of time. These acquisitions have been geographically concentrated in our core areas where we possess considerable operating expertise and realize economies of scale. We principally target acquisitions which have significant development potential, are in close proximity to existing properties, have a high degree of operatorship and can be integrated with minimal incremental administrative cost.

*Large, Geographically-Concentrated Property Base.* We own interests in approximately 10,000 wells located primarily in our core areas. As a result of this large, geographically-concentrated property base, the opportunity to generate positive results through the application of improved production technologies and to achieve economies of scale is enhanced while the risk of material adverse financial consequences from unexpected production interruptions is minimized. We have five district offices in our core areas and employ approximately 130 pumpers and other field personnel to provide onsite management of our properties.

**Forward-Looking Statements**

All statements in this document other than purely historical information are forward-looking statements within the meaning of the federal securities laws. These statements reflect our current expectations and are based on our historical operating trends, our proved reserve and fixed-price contract positions as of December 31, 2000, and other information currently available to us. Forward-looking statements include statements regarding our future drilling plans and objectives, and related exploration and development budgets, and number and location of planned wells, and statements regarding the quality of our properties and potential reserve and production levels. These statements may be preceded or followed by, or otherwise include the words "believes", "expects", "anticipates", "intends", "plans", "estimates", "projects", or similar expressions or statements that certain events "will" or "may" occur. These statements assume, among other things, that no significant changes will occur in the operating environment for our oil and gas properties and that there will be no material acquisitions or divestitures except as disclosed herein.

We caution that the forward-looking statements are subject to all the risks and uncertainties incident to the acquisition, exploration, development and marketing of oil and gas reserves. These risks include, but are not limited to, commodity price, counterparty, environmental, drilling, reserves, operations and production risks. Certain of these risks are described elsewhere in this document. See "Item 7 -- Management's Discussion and Analysis of Financial Condition and Results of Operations -- Outlook for Fiscal Year 2001." Moreover, we may make material acquisitions or divestitures, modify our fixed-price contract positions by entering into new contracts or terminating existing contracts, or enter into financing transactions. None of these can be predicted with certainty and are not taken into consideration in the forward-looking statements made in this document.

Statements concerning fixed-price contract, interest rate swap and other financial instrument fair values and their estimated contribution to future results of operations are based upon market information as of a specific date. This market information is often a function of significant judgment and estimation. Further, market prices for oil and gas and market interest rates are subject to significant volatility.

For all of these reasons, actual results may vary materially from the forward-looking statements and there is no assurance that the assumptions used are necessarily the most likely. We expressly disclaim any obligation or undertaking to release publicly any updates regarding any changes in our expectations with regard to the subject matter of any forward-looking statements or any changes in events, conditions or circumstances on which any forward-looking statements are based.

**Recent Developments**

The following information discusses certain of our more significant accomplishments during the year ended December 31, 2000.

*2000 Drilling Program*. Our drilling program once again posted strong results in 2000. We drilled 461 wells, of which 431 wells were completed as commercial producers for a drilling success rate of 93%. This well count included nine exploratory wells, 56% of which were completed as producers, and 452 development wells, 94% of which were completed as producers. Through this program, 278 Bcfe of proved reserves were added to our reserve base at an all-in finding and development cost (total costs incurred to explore and develop oil and gas properties divided by proved reserves added through extensions and discoveries and revisions of previous estimates) of $.86 per Mcfe. The drilling program replaced 203% of production with drilling capital expenditures totaling $238.9 million, or 86% of cash flows from operating activities. The year ended December 31, 2000 marked the seventh consecutive year that reserves added through our drilling program exceeded production. See "Item 2 -- Properties -- Costs Incurred and Drilling Results."

*Proved Reserve Acquisitions.* Proved reserve acquisitions in 2000 included the purchase of substantially all of the oil and gas properties of Costilla Energy, Inc. for approximately $122 million in cash. The acquired properties were comprised of 135 Bcfe of net proved reserves included in 1,011 gross (607 net) producing wells at closing. The majority of the Costilla properties are located within our three core operating areas. We also closed several smaller acquisitions during the year. In total for 2000, we acquired 204 Bcfe of proved reserves at an average finding cost of $.82 per Mcfe.

*Proved Reserves.* Our proved reserves as of December 31, 2000 grew 23% in relation to 1999 and were comprised of 33 MMBbls of oil and 1.6 Tcf of natural gas, or 1.8 Tcfe. This reserve growth represents a production replacement ratio of approximately 350%. Our estimated future net revenues from proved reserves were $8.0 billion as of December 31, 2000. The present value of future net revenues discounted at 10% was $3.7 billion. See "Item 2 -- Properties -- Reserves" and Note 13 of the Notes to Consolidated Financial Statements appearing elsewhere in this document.

*Financial Results*. We reported net income of $98.3 million, or $2.29 per share, on total revenue of $477.3 million for 2000, the highest net income reported in our history. This compares to net income of $21.4 million, or $.53 per share, on total revenue of $302.6 million for 1999. We reported record cash flows from operating activities before working capital changes of $337.4 million for the year ended December 31, 2000, which compares to $171.8 million for 1999, an increase of 96%. Cash flows provided by operating activities after consideration for the change in working capital was $278.0 million, which compares to $181.6 million for 1999. The year 2000 increase in earnings and operating cash flows was achieved primarily through significantly higher oil and gas prices and growth in gas production. Record EBITDAX of $381.8 million and record oil and gas production of 137 Bcfe were also achieved in 2000. See "Item 7 -- Management's Discussion and Analysis of Financial Condition and Results of Operations -- Results of Operations -- Fiscal Year 2000 Compared to Fiscal Year 1999."

**Acquisitions**

We have completed a significant number of proved reserve acquisitions during the past five years, including two individually large acquisitions for which we invested $122 million and $340 million, respectively. In 2000, we acquired substantially all of the oil and gas properties of Costilla Energy, Inc. for approximately $122 million in cash. The acquired properties were comprised of 135 Bcfe of net proved reserves included in 1,011 gross (607 net) producing wells at closing. The majority of the Costilla properties are located within our three core operating areas. We also closed several smaller acquisitions during the year. In total for 2000, we acquired 204 Bcfe of proved reserves at an average finding cost of $.82 per Mcfe. The following table summarizes our acquisition activity for the five years ended December 31, 2000:

**SUMMARY ACQUISITION INFORMATION**

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 | 1997 | 1996 | Total |
| Estimated proved reserves acquired (Bcfe) | 204 | 41 | 7 | 234 | 76 | 562 |
| Acquisition cost (MM$) | $ 167.7 | $ 36.9 | $ 4.1 | $ 349.0 | $ 36.1 | $ 593.8 |
| Acquisition cost per Mcfe (1) | $ .82 | $ .90 | $ .56 | $ 1.49 | $ .48 | $ 1.06 |

(1) - Results for 1997 include the purchase accounting impact of the American Exploration acquisition.

We are actively involved in the screening of potential acquisitions and the development and implementation of strategies for specific acquisitions. Our staff of reservoir engineers, geologists, production engineers, landmen and accountants have substantial experience in evaluating and acquiring oil and gas reserves. We primarily seek acquisitions in our core areas in which our experience and existing operations will enable us to readily integrate the acquired properties. Acquisitions are targeted which emphasize natural gas, have significant further development and exploration potential, and a high degree of operatorship. We prefer to operate our properties whenever possible in order to provide more control over the operation and development of the properties and the marketing of production. We also pursue additional interests in our operated properties from holders of non-operating interests to increase our percentage ownership at attractive acquisition prices.

The market for proved reserve acquisitions is uncertain and we cannot predict the amount of capital ultimately to be invested in acquisitions during 2001. Although a significant number of oil and gas properties are predicted to be placed on the market, higher oil and gas commodity prices are expected to raise sellers' price expectations.

**Marketing**

*Fixed-Price Contracts*

*Description.* We have entered into long-term physical delivery contracts, energy swaps, collars and basis swaps, which we collectively refer to as fixed-price contracts, to reduce exposure to decreases in oil and gas prices which are subject to significant and often volatile fluctuation. These contracts allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production and benefit us when market prices are less than the fixed prices provided in our fixed-price contracts. However, we will not benefit from market prices that are higher than the fixed prices in such contracts for our hedged production. At December 31, 2000, these contracts hedge 82 Bcf of future gas production in 2001, and 120 Bcf thereafter, representing 11% of estimated total proved reserves. The fixed prices in these contracts generally escalate over the contract term. Fixed-price contract volume and price information by year for the next five years and thereafter is shown at "Item 7A -- Quantitative and Qualitative Disclosures About

Market Risk -- Fixed-Price Contracts." We have historically hedged a significant portion of our natural gas and crude oil production. In recent years, a progressively smaller share of our production and reserve additions have been hedged due to our belief that longer-term demand and supply fundamentals for natural gas imply the potential for continued strength in natural gas prices. More recent hedging activity has been for shorter periods of time, generally less than 12 months, when market conditions have been viewed as favorable. We may decide to hedge a greater or smaller share of production in the future depending on market conditions, capital investment considerations and other factors.

*Delivery Contracts.* We have entered into fixed-price natural gas delivery contracts with natural gas pipeline marketing affiliates, a municipality, an independent power producer and other end users. Typically, these contracts require us to deliver, and the purchaser to take, specified quantities of natural gas at specified fixed prices, over the life of the contracts. Delivery contracts hedge 100 Bcf of future gas production as of December 31, 2000, representing 6% of estimated proved natural gas reserves. The contract term varies with each contract, ranging from a period of less than four years to approximately 17 years. We meet our fixed-price delivery contract requirements through purchases of natural gas in markets local to the delivery point at the most attractive prices available. The contracts generally permit us to deliver natural gas at our choice of several pipeline or customary industry delivery points, permitting some market flexibility to us in purchasing required natural gas supplies and making deliveries and reducing transportation risks. Each contract is individually negotiated based on the purchaser's specified needs.

*Energy Swaps and Collars.* We enter into energy swaps and collars as a fixed-price seller in order to reduce our exposure to falling market oil and gas prices, assuring ourselves of fixed prices for the sale of our oil and gas production. At December 31, 2000, we were a party to ten energy swaps, which collectively hedge 62 Bcf of future gas production. The contract term varies with each contact, ranging from a period of less than one year to approximately seven years. The variables in an energy swap transaction are a fixed price, an index price, a specified quantity and a period. One of the parties is designated as the fixed-price purchaser and whenever the fixed price exceeds the index price for a given date or period, the fixed-price purchaser pays the other party, the fixed-price seller, the difference between the fixed price and the index price. Whenever the index price is in excess of the fixed price, the fixed-price seller pays the difference between the index price and the fixed price to the fixed-price purchaser. In this way the parties may, without physical delivery of oil or gas, hedge against uncertainties and risk created by fluctuations in oil and gas prices in connection with such party's actual physical supply, purchase or sale commitments or requirements. Natural gas collars contain a fixed floor price (put) and ceiling price (call). If the market price of natural gas exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price. If the market price of natural gas is between the call and the put strike price, then no payments are due from either party. We were a party to seven fixed-price collars at December 31, 2000 which hedged 39 Bcf of gas production in 2001.

*Counterparties.* The following table summarizes certain information concerning our natural gas fixed-price contracts and associated counterparties at December 31, 2000:

**NATURAL GAS FIXED-PRICE CONTRACT VOLUMES BY COUNTERPARTY**

| | Volumes Committed (BBtu) | | | | Percentage |
|---|---|---|---|---|---|
| | Delivery Contracts | Energy Swaps | Collars | Total | of Total Volume |
| **Type of Counterparty:** | | | | | |
| Pipeline marketing affiliates | 50,238 | 23,420 | -- | 73,658 | 36% |
| Independent power producer | 30,108 | -- | -- | 30,108 | 15 |
| Financial institutions | -- | 17,150 | 39,100 | 56,250 | 28 |
| Other | 20,040 | 21,900 | -- | 41,940 | 21 |
| Total | 100,386 | 62,470 | 39,100 | 201,956 | 100% |

For additional information concerning our fixed-price contracts, see "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts."

*Wellhead Marketing*

The majority of our wellhead gas production is sold to a variety of purchasers on the spot market or dedicated to contracts with market-sensitive pricing provisions. We market substantially all of the undedicated natural gas produced from our operated wells. Additionally, the majority of the oil and condensate produced from our operated properties is sold on a market price sensitive basis. During 2000, we had gas sales to three unrelated purchasers which approximated 17%, 17% and 14% of total revenues, respectively. See Note 9 of the Notes to Consolidated Financial Statements appearing elsewhere in this document. The loss of any wellhead purchaser is not anticipated to have a material adverse effect on us because there are a substantial number of alternative purchasers in the markets in which we sell our wellhead production.

**Competition**

The oil and gas industry is highly competitive. We compete with major oil and gas companies, other independent oil and gas concerns, gas marketing companies and individual producers and operators for proved reserve and undeveloped acreage acquisitions, the development, production and marketing of oil and gas, and for contracting equipment and securing personnel. Many of these competitors have financial and other resources which exceed those available to us. Competition in the regions in which we own properties may result in occasional shortages or unavailability of drilling rigs and other equipment used in drilling activities, and limited pipeline capacity and access. These circumstances could result in curtailment of activities, increased costs, delays or losses in production or revenues or cause interests in oil and gas leases to lapse. We believe that our acquisition, development, production and marketing capabilities, financial resources and the experience of our management and staff enable us to compete effectively.

**Regulation**

The oil and gas industry is extensively regulated by federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion. Numerous departments and agencies at the federal, state and local level have issued rules and regulations affecting the oil and gas industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. Inasmuch as such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such regulations. We believe that our operations and facilities comply in all material respects with applicable laws and regulations as currently in effect and that the existence and enforcement of such laws and regulations have no more restrictive effect on our operations than on other similarly situated companies in the oil and gas industry.

*Drilling and Production*

Our operations are subject to various types of regulation at federal, state and local levels. This regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation requirements. These include the regulation of the size and shape of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of oil and gas properties. In this regard, some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. These regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which we can drill.

We have operated and non-operated working interests in various oil and gas leases in the Gulf of Mexico which were granted by the federal government and are administered by the Minerals Management Service, a federal agency commonly referred to as the MMS. These leases were issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders, which are subject to change. For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to commencement. In addition to permits required from other agencies, such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the outer continental shelf to meet stringent engineering and construction specifications, and has established other regulations governing the plugging and abandoning of wells located offshore and the removal of all production facilities. With respect to any of our operations conducted on offshore federal leases, liability may generally be imposed under the Outer Continental Shelf Lands Act for costs of clean-up and damages caused by pollution resulting from such operations. Under certain circumstances including, but not limited to, conditions deemed to be a threat or harm to the environment, the MMS may also require any of our operations on federal leases to be suspended or terminated in the affected area.

*Environmental*

Our operations are subject to numerous federal and state laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of hazardous substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. State laws often impose requirements to remediate or restore property used for oil and gas exploration and production activities, such as pit closure and plugging abandoned wells. Although we believe that our operations and facilities are in compliance in all material respects with applicable environmental and health and safety laws and regulations, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that substantial costs and liabilities will not be incurred in the future. Moreover, the recent trend toward stricter standards in environmental legislation, regulation and enforcement is likely to continue.

Our operations may generate wastes that are subject to the Federal Resource Conservation and Recovery Act and comparable state statutes. The Environmental Protection Agency, also referred to as the EPA, has limited the disposal options for certain hazardous wastes and may adopt more stringent disposal standards for nonhazardous wastes. Furthermore, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes" under the Federal Resource Conservation and Recovery Act which would regulate such reclassified wastes and require government permits for transportation, storage and disposal. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the oil and gas industry in general. State initiatives to further regulate oil and gas wastes could have a similar impact on us.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as the "superfund" law, imposes liability, regardless of fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the current or previous owner and operator of a site and companies that disposed, or arranged for the disposal, of the hazardous substance found at a site. The superfund law also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs of such action. In the course of operations, we generate wastes that may fall within this act's definition of "hazardous substances." We may be responsible under the act for all or part of the costs to clean up sites at which these substances have been disposed. We have not been named by the EPA or alleged by any third party as being potentially responsible for costs and liabilities associated with alleged releases of any "hazardous substance" at any superfund site.

Our operations are subject to the requirements of the Federal Occupational Safety and Health Act and comparable state statutes. The Federal Occupational Safety and Health Act hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act, and similar state statutes require that information be organized and maintained about hazardous materials used or produced in its operations. Certain of this information must be provided to employees, state and local government authorities and citizens.

The Oil Pollution Act requires the lessee or permittee of an offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million, which may be increased to $150 million in certain circumstances to cover liabilities related to an oil spill. The act also subjects responsible parties to strict, joint and several and potentially unlimited liability for removal costs and certain other damages caused by an oil spill covered by the statute.

*Natural Gas Sales Transportation*

In the past, there were various federal laws which regulated the price at which natural gas could be sold. Since 1978, various federal laws have been enacted which have resulted in the termination on January 1, 1993 of all price and non-price controls for natural gas sold in "first sales." As a result, on and after January 1, 1993, none of our natural gas production is subject to federal price controls.

The transportation and sale for resale of natural gas is subject to regulation by the Federal Energy Regulatory Commission, also referred to as the FERC, under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Commencing in 1985, the FERC promulgated a series of orders and regulations adopting changes that significantly affect the transportation and marketing of natural gas. These changes have been intended to foster competition in the natural gas industry by, among other things, inducing or mandating that interstate pipeline companies provide nondiscriminatory transportation services to producers, distributors and other shippers, so-called “open access” requirements. The effect of the foregoing regulations has been to create a more open access market for natural gas purchases and sales and has enabled us, as a producer, buyer and seller of natural gas, to enter into various contractual natural gas sale, purchase and transportation arrangements on unregulated, privately negotiated terms.

We own a 75-mile intrastate pipeline and associated compression facilities in the Sonora area of West Texas. Approximately 93% of the gas transported in this pipeline system during 2000 was owned by us. The operation of this system is subject to regulation by the Texas Railroad Commission.

**Certain Operational Risks**

Our operations are subject to the risks and uncertainties associated with drilling, producing and transporting oil and gas. We must incur significant expenditures for the identification and acquisition of properties and for the drilling and completion of wells. Drilling activities are subject to numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. Our prospects for future growth will depend on our ability to replace current reserves through drilling, acquisitions, or both. Our ability to market our oil and gas production depends upon the availability and capacity of oil and gas gathering systems and pipelines, among other factors, many of which are beyond our control.

Our operations are subject to the risks inherent in the oil and gas industry, including the risks of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental accidents such as oil spills, gas leaks, salt water spills and leaks, ruptures or discharges of toxic gases, the occurrence of any of which could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including the presence of unanticipated pressure or irregularities in formations, accidents, title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery of equipment. In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above. There can be no assurance that the levels of insurance maintained by us will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance or its availability at commercially acceptable premium levels.

**Employees**

As of February 1, 2001, we had approximately 400 employees. We believe that relations with our employees are satisfactory. Our employees are not covered by a collective bargaining agreement.

**Relationship Between the Company and S.A. Louis Dreyfus et Cie**

S.A. Louis Dreyfus et Cie beneficially owns approximately 44% of our common stock. Through their effective ability to elect all of our directors, S.A. Louis Dreyfus et Cie has the ability to control our business and affairs, including decisions with respect to the acquisition or disposition of assets and the future issuance of common stock or other securities. S.A. Louis Dreyfus et Cie also has the ability to control our drilling, operating and acquisition expenditure plans. There is no agreement that would prevent S.A. Louis Dreyfus et Cie from acquiring additional shares of common stock. Approximately one-half of the shares owned by S.A. Louis Dreyfus et Cie are required to be pledged to a judgment creditor of one of their subsidiaries pending the outcome of an appeal of the judgment. This appeal is expected to be completed during 2001. The judgment is unrelated to us. The sale of all or a portion of these shares after the completion of the appeal could result in a change in control. S.A. Louis Dreyfus et Cie's other principal activities include the international merchandising and exporting of various commodities, ownership and management of ocean vessels, real estate and crude oil refining.

We have a services agreement with S.A. Louis Dreyfus et Cie pursuant to which S.A. Louis Dreyfus et Cie provides various services (principally insurance-related services). These services historically have been supplied to us by S.A. Louis Dreyfus et Cie, and the services agreement provides for the further delivery of these services, but only to the extent requested by us. We reimburse S.A. Louis Dreyfus et Cie for a portion of the salaries of employees performing requested services based on the amount of time expended, all direct third party costs incurred by S.A. Louis Dreyfus et Cie in rendering requested services and overhead costs equal to 40% of the allocated salary costs. The services agreement will continue until terminated by either party upon 60 days prior written notice to the other party. In the event of termination of the services agreement by S.A. Louis Dreyfus et Cie, we have an option to continue the agreement for up to 180 days to enable us to arrange for alternative services. Substantially all the services provided under the agreement in 2000 relate to participation in certain insurance programs of S.A. Louis Dreyfus et Cie.

**Potential Conflicts of Interest**

The nature of our business and that of S.A. Louis Dreyfus et Cie may give rise to conflicts of interest between us. Conflicts could arise, for example, with respect to intercompany transactions between us and S.A. Louis Dreyfus et Cie, competition in the marketing of natural gas, the issuance of additional shares of voting securities, the election of directors or the payment of dividends.

We and S.A. Louis Dreyfus et Cie have entered into intercompany transactions and agreements incident to our respective businesses in the past. Such transactions and agreements have related to, among other things, the purchase and sale of natural gas and the provision of certain corporate services. It is the intention of both parties that we operate independently, other than receiving services as contemplated by the services agreement, but we may enter into material intercompany transactions. In any event, we intend that the terms of any future transactions and agreements between us will be at least as favorable to us as could be obtained from unaffiliated third parties.

S.A. Louis Dreyfus et Cie does not currently engage in oil and gas acquisition, development or exploration activities except through its beneficial ownership of our common stock. However, as part of S.A. Louis Dreyfus et Cie's business strategy, S.A. Louis Dreyfus et Cie may, from time to time, engage in these activities directly or indirectly in the future. S.A. Louis Dreyfus et Cie is also actively engaged in the trading of oil and gas which includes the use of fixed-price contracts. We have not adopted any special procedures to address potential conflicts of interest between us relating to such potential competition. However, we do not currently anticipate that any potential competition with S.A. Louis Dreyfus et Cie for fixed-price contracts would adversely affect our ability to hedge our production.

**Recent Sales of Unregistered Securities**

In December 2000, we issued a total of 363,541 shares of common stock to four purchasers upon exercise of outstanding warrants. The warrants were initially issued by American Exploration Company and were assumed by us in connection with the acquisition of American Exploration Company in 1997. The exercise price of the warrants was \$17.69 per share of common stock, and the exercise was paid by the warrant holders by the surrender of portions of the warrants having a value at the time of surrender equal to the exercise price paid as permitted by the terms of the warrants. The shares of common stock issued upon exercise of the warrants were issued in reliance on the exemption from registration afforded by Section 4(2) of the Securities Act of 1933, as amended. Among the facts supporting our reliance on such exemption are that the warrants were originally privately placed to, and continued to be held by, a small group of institutional investors and that the investors acquired the warrants and the underlying shares for their own accounts and without intention of distributing or reselling the shares except in compliance with applicable securities laws. We registered the resale of the shares by the holders in accordance with the registration rights of the holders under the terms of the warrants.

**Certain Definitions**

The terms defined in this section are used throughout this filing:

*Bbl.* One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

*Bcf.* Billion cubic feet.

*Bcfe.* Billion cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

*Btu.* British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

*BBtu.* Billion Btus.

*Developed Acreage.* The number of acres which are allocated or assignable to producing wells or wells capable of production.

*Development Location.* A location on which a development well can be drilled.

*Development Well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive in an attempt to recover proved undeveloped reserves.

*Drilling Unit.* An area specified by governmental regulations or orders or by voluntary agreement for the drilling of a well to a specified formation or formations which may combine several smaller tracts or subdivides a large tract, and within which there is usually some right to share in production or expense by agreement or by operation of law.

*Dry Hole.* A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

*EBITDAX.* EBITDAX is defined herein as income (loss) before interest, income taxes, depreciation, depletion and amortization, impairment, exploration costs and change in derivative fair value. We believe that EBITDAX is a financial measure commonly used in the oil and gas industry as an indicator of a company's ability to service and incur debt. However, EBITDAX should not be considered in isolation or as a substitute for net income, cash flows provided by operating activities or other data prepared in accordance with generally accepted accounting principles, or as a measure of a company's profitability or liquidity. EBITDAX measures as presented may not be comparable to other similarly titled measures of other companies.

*Estimated Future Net Revenues.* Revenues from production of oil and gas, net of all production-related taxes, lease operating expenses, capital costs and abandonment costs.

*Exploratory Well.* A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

*Finding Cost.* Total costs incurred to acquire, explore and develop oil and gas properties divided by the increase in proved reserves through acquisition of proved properties, extensions and discoveries, improved recoveries and revisions of previous estimates.

*Gross Acre.* An acre in which a working interest is owned.

*Gross Well.* A well in which a working interest is owned.

*Infill Drilling.* Drilling for the development and production of proved undeveloped reserves that lie within an area bounded by producing wells.

*Lease Operating Expense.* All direct costs associated with and necessary to operate a producing property.

*MBbls.* Thousand barrels.

*MBtu.* Thousand Btus.

*Mcf.* Thousand cubic feet.

*Mcfe.* Thousand cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

*MMBbls.* Million barrels.

*MMBtu.* Million Btus.

*MMcf.* Million cubic feet.

*MMcfe*. Million cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

*Natural Gas Liquids.* Liquid hydrocarbons which have been extracted from natural gas (e.g., ethane, propane, butane and natural gasoline).

*Net Acres or Net Wells.* The sum of the fractional working interests owned in gross acres or gross wells.

*Overriding Royalty Interest.* An interest in an oil and gas property entitling the owner to a share of oil and gas production free of well or production costs.

*Present Value.* When used with respect to oil and gas reserves, present value means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development costs, and future abandonment costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. The prices used to estimate future net revenues do not consider the effects of fixed-price contracts.

*Productive Well*. A well that is producing oil or gas or that is capable of production.

*Proved Developed Reserves.* Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

*Proved Reserves.* The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.

*Proved Undeveloped Reserves.* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

*Recompletion.* The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

*Reserve Life.* A measure of how long it will take to produce a quantity of reserves, calculated by dividing estimated total proved reserves by production for the twelve-month period prior to the date of determination (in gas equivalents).

*Reserve Replacement Ratio.* A measure of proved reserve growth determined by dividing the net change in reserve quantities between two dates, excluding production, by the quantity produced between the two dates.

*TBtu.* One trillion Btus.

*Tcfe.* Trillion cubic feet of gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

*Undeveloped Acreage.* Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves.

*Working Interest.* The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

## Item 2 -- PROPERTIES

### General

Our oil and gas acquisition, exploration and development activities are conducted mainly in our core areas: the Permian Region which includes west Texas, southeast New Mexico and the San Juan Basin; the Mid-Continent Region which includes Oklahoma, Kansas, the panhandle of Texas, east Texas, southwest Arkansas and north Louisiana; and the Gulf Coast Region which includes south Texas and offshore Gulf of Mexico. Proved reserves as of December 31, 2000 consisted of 33 MMBbls of oil and 1.6 Tcf of natural gas, totaling 1.8 Tcfe. We have ownership interests in approximately 10,000 producing wells, and we operate approximately 3,900 of these wells. Our operated wells contain 79% of our total proved reserves. Net average daily production during 2000 was 7.8 MBbls of oil and 327.5 MMcf of natural gas, or 374.4 MMcfe. We drilled 452 developmental oil and gas wells, of which 426 wells, or 94%, were completed as commercial producers, and nine exploratory wells, of which five wells, or 56%, were successfully completed, during 2000.

We have allocated $290 million for our 2001 drilling program, subject to revision based upon oil and gas prices, proved reserve acquisitions and other factors. Approximately $64 million of this total, or 22%, has been allocated to exploration activities and $226 million, or 78%, has been allocated to development activities. We expect that this drilling expenditure will result in the drilling of about 590 wells, including 20 exploratory wells and 570 development wells. See “Item 7 -- Management’s Discussion and Analysis of Financial Condition and Results of Operations -- Outlook for Fiscal Year 2001.”

## Core Areas

The following table sets forth certain information regarding our activities in each of our principal producing areas as of December 31, 2000:

**CORE AREAS**

| | Permian | Mid-Continent | Gulf Coast | Total |
|---|---|---|---|---|
| **Property Statistics:** | | | | |
| Proved reserves (Bcfe) | 906 | 577 | 325 | 1,808 |
| Percent of total proved reserves | 50% | 32% | 18% | 100% |
| Gross producing wells | 5,668 | 3,368 | 927 | 9,963 |
| Net producing wells | 2,528 | 1,169 | 308 | 4,005 |
| Gross acreage | 1,349,200 | 952,484 | 452,935 | 2,754,619 |
| Net acreage | 560,422 | 455,188 | 214,567 | 1,230,177 |
| Potential drill sites | 1,205 | 745 | 174 | 2,124 |
| **2000 Results:** | | | | |
| Gross wells drilled | 354 | 61 | 46 | 461 |
| Gross successful wells | 343 | 53 | 35 | 431 |
| Drilling success | 97% | 87% | 76% | 93% |
| Production (Bcfe) | 47.7 | 38.2 | 51.1 | 137.0 |
| Average net daily production (MMcfe) | 130.2 | 104.5 | 139.7 | 374.4 |
| Lease operating expense per Mcfe | $ .45 | $ .46 | $ .34 | $ .41 |
| **2001 Drilling Budget (MM$):** | | | | |
| Development | $ 115 | $ 55 | $ 56 | $ 226 |
| Exploration | 4 | 10 | 50 | 64 |
| Total | $ 119 | $ 65 | $ 106 | $ 290 |

### *Permian Region*

We are actively involved in development and exploration activities in several areas within the Permian Region. These areas include the Sonora area of west Texas and the Delaware Basin of southeast New Mexico, among others. Our properties in the Permian Region contain 906 Bcfe of proved reserves, representing approximately one-half of our total reserve base, in 5,668 wells. We drilled 354 wells in the Permian Region in 2000 and daily production averaged 130 MMcfe per day. We have identified 1,205 potential locations in this region of which 478 have been assigned proved undeveloped reserves. Plans for this region in 2001 include the drilling of approximately 430 wells and a total investment of $119 million, including acreage and seismic acquisition.

*Sonora Area*

The Sonora area is located in the west Texas counties of Schleicher, Crockett, Sutton and Edwards. It is primarily comprised of five fields: Sawyer, Shurley Ranch, MMW, Aldwell Ranch and Whitehead, which are located on the northeast side of the Val Verde Basin of west central Texas. We own an average 60% working interest in 3,497 wells and operate 2,038 of these wells. In our operated wells, we own an average 98% working interest. Net daily production from the Sonora area during 2000 averaged 95 MMcfe per day. Production is predominately from the Canyon formation at depths ranging from 2,500 to 6,500 feet and the Strawn formation at depths ranging from 7,000 to 9,000 feet.

*Canyon Formation.* Natural gas in the Canyon formation is stratigraphically trapped in lenticular sandstone reservoirs and the typical Sonora area well encounters numerous such reservoirs over the formation's gross thickness of approximately 1,500 feet. The Canyon reservoirs tend to be discontinuous and to exhibit low porosity and permeability, characteristics which reduce the area that can be effectively drained by a single well. These characteristics have encouraged Canyon infill drilling. Initial wells were drilled on 640 acre drilling units, but well performance characteristics have shown that denser well spacing is necessary for effective drainage. We continue to drill infill wells in these units and, in some areas, the Canyon is developed on 40 acre spacing.

*Strawn Formation.* The Strawn formation, a shallow-marine, fossiliferous limestone, produces natural gas from fractures and irregularly distributed porosity trends draped across anticlinal features. Original field development took place on 640 acre units, with subsequent infill programs downsizing some areas to 80 acre density. Testing of the

Strawn formation in Sonora wells, for which the primary drilling objective was the Canyon formation, has been an attractive play for us. Because the Strawn formation lies less than 1,000 feet below the Canyon formation, the incremental cost to evaluate the Strawn has been relatively minor. Strawn production is generally commingled with the Canyon production stream.

We have maintained an aggressive development drilling program in the Sonora area since 1993, having drilled 917 Canyon and Strawn wells with only 29 dry holes. The 2000 drilling program resulted in the drilling of 210 wells, 204 of which were completed as commercial producers. We plan to drill approximately 300 wells in Sonora during 2001, the majority of which are relatively low risk locations. We have identified over 1,000 potential locations on our acreage, of which 407 have been assigned proved undeveloped reserves. Subject to further study and drilling results, we believe additional proved reserves will ultimately be attributed to many of the other locations. In addition to infill drilling potential, a number of recompletion possibilities are present in existing wellbores.

*Southeast New Mexico*

We are also active in southeastern New Mexico in the Delaware Basin, where the primary objectives are the Morrow sand and the Wolfcamp carbonate. The Morrow sands are deposited in fluvial channels which trend from northwest to southeast. The Wolfcamp carbonate in our area of interest is deposited in deep water alluvial fans along a major reef complex and is primarily oil production. These reservoirs exhibit excellent porosity and permeability at depths between 10,000 and 15,000 feet. These objectives also lend themselves to the use of 3D seismic technology and computerized mapping. It is anticipated that approximately 55 wells will be drilled in this region in 2001.

***Mid-Continent Region***

We have been actively involved in the Mid-Continent Region since our inception and over the past ten years have acquired substantial additional acreage and proved reserves in the area through multiple synergistic acquisitions. We operate approximately 1,370 wells in the Mid-Continent Region. Our properties are located in and along the northern shelf of the Anadarko Basin in western Oklahoma, in the deeper Anadarko Basin in the Texas panhandle, and in Kansas. This region also includes properties in the Smackover Trend in southern Arkansas and properties in east Texas. Development of our Mid-Continent Region properties began in the late 1970's. Production is predominately natural gas from productive formations of Pennsylvanian and Pre-Pennsylvanian age rock. Productive depths range from 3,000 to 17,000 feet. Pre-Pennsylvanian reservoirs include the Chester, Mississippi and Hunton formations, with greater production from these formations occurring in highly fractured carbonate intervals. Pennsylvanian reservoirs include the Granite Wash, Red Fork, Atoka, Morrow and Springer sandstones. The stratigraphic nature of these reservoirs frequently provides for multiple targets in the same wellbores. Spacing in these formations is generally on 640 acres with extensive increased density drilling having occurred over the last 15 years. Our two primary areas of focus in the Mid-Continent are the Watonga-Chickasha Trend in central Oklahoma and the Tuttle field in southern Oklahoma.

We have pursued an active low-risk infill drilling program in the Mid-Continent area over the past five years, including the drilling of 61 wells in 2000. Average net daily production during 2000 was 104 MMcfe per day for this region. We have ownership in 3,368 wells with proved reserves of 577 Bcfe. We have identified 745 potential locations in the Mid-Continent Region, of which 216 have been assigned proved undeveloped reserves. We plan to drill approximately 115 wells in this area during 2001.

*Watonga-Chickasha Trend*

The Morrow/Springer sands located in central Oklahoma were deposited as bars and channels along an ancient coast line more than 350 miles long. These sands exhibit excellent porosity and permeability at depths of 10,000 to 13,000 feet. Multiple objectives of up to a dozen sands have allowed increased drilling from one well per 640 acres to as many as four wells per 640 acres. The majority of the wells drilled in this trend are lower risk development wells. We plan to drill at least two exploratory tests seeking to discover new bars or channels and approximately 40 development wells during 2001.

*Tuttle Field*

The primary objectives in the Tuttle field are the Mississippi, Mayes, Skinner and Hunton sands, with the total depth of wells drilled in this field averaging 10,000 feet. We operate 131 gross wells in the field and own an average 53% working interest. During 2000, we successfully completed 12 wells and significantly increased our ownership through an acquisition late in the third quarter. Net daily production during 2000 averaged 9 MMcfe per day. We plan to drill approximately 15 development wells in this field in 2001.

*Smackover Trend*. Our operations in the Smackover Trend of southwestern Arkansas are focused primarily in the Midway field, which we operate. The Midway field is located in Lafayette County, Arkansas and produces oil from the Smackover formation at an average depth of 6,500 feet. We own an average 81% working interest in this waterflood unit.

***Gulf Coast Region***

We made our first acquisition in the Gulf Coast Region in 1991 and began development drilling activities in this area in 1992. We are now actively involved in an extensive exploration and development program in south Texas and, to a lesser extent, offshore in the Gulf of Mexico. Our properties in this region number 927 wells and include 325 Bcfe of proved reserves. We drilled 46 wells in the Gulf Coast Region during 2000 and daily production averaged 140 MMcfe per day. We have identified 174 potential locations in this region of which 76 have been assigned proved undeveloped reserves. Plans for this region in 2001 include the drilling of approximately 45 wells and a total investment of $106 million, including acreage and seismic acquisition.

*Lavaca County Area*

We began our involvement in Lavaca County, Texas, in 1996 to explore and drill primarily for the Lower Wilcox formation. Secondary targets include the shallower Upper Wilcox, Miocene, Frio and Yegua targets. Working interests in these projects, including the Yoakum Gorge and S.W. Speaks projects, initially ranged from 25% to 35%. Subsequent acquisitions in 1997, 1998 and 2000 have more than doubled our interests in these fields and have expanded our position in the Wilcox Trend further to the east to include the Provident City field.

We now hold working interests ranging from 30% to 100% in 65,000 gross acres in Lavaca County. Since this project began, we have participated in 76 Lower Wilcox wells, over 80% of which have been successfully completed as producers. Approximately 1,200 square miles of high-fold 3D seismic data has been acquired since 1996 which continues to be evaluated. The target zones are the Lower Wilcox sands from 11,000 to 17,000 feet and the shallow Miocene, Frio, Yegua and Upper Wilcox sands ranging in depth from 3,500 to 8,000 feet.

Our Lower Wilcox drilling program in 2000 resulted in the successful completion of 26 wells, including five exploratory tests. The Lower Wilcox sands are part of an ancient deltaic system deposited across an unstable muddy continental shelf. The rapid subsidence of the underlying beds allowed accumulation of massive Wilcox sand packages with a high degree of structural complexity. These deep structures have significant potential, ranging up to 200 Bcf per field. Production rates for wells drilled in this program have ranged as high as 40 MMcfe per day. Drilling plans for 2001 include approximately 45 Lower Wilcox wells in Lavaca County, of which 13 are expected to be exploratory.

*Wilcox Trend*

As an extension to our Wilcox success in Lavaca County, we acquired leasehold positions in Zapata, Goliad and Webb Counties during 1999. In the En Seguido field located in Zapata County, we drilled the Laura Lopez #1 well, which was completed at a rate of 16 MMcf of natural gas per day. An offset development well was completed during 2000 at a rate of over 40 MMcf of natural gas per day. Three additional development wells were completed in this field during 2000 at a combined rate of 16 MMcf per day. Up to three additional En Seguido wells are planned for 2001. In addition to this En Seguido field activity, we completed two Wilcox tests on the W. Martinez prospect, also in Zapata County, which is ten miles to the north of En Seguido. Initial production for these two wells was a combined 12 MMcf per day. In total, we own approximately 15,000 gross acres in Zapata County with working interests ranging from 38% to 100%. We also own 500 square miles of 3D seismic information in Zapata County and plan to drill a total of six development wells and three exploratory wells in 2001.

In Goliad County, we acquired approximately 3,100 gross acres in two prospects, the Cologne and Swickheimer prospects. Our working interests in these prospects range from 37% to 54%. Two exploratory tests for the Lower Wilcox were completed in 2000 for a combined rate of 12 MMcf of natural gas per day. At least one additional exploratory test is planned for 2001 in the Cologne prospect.

*Offshore Area*

We own working interests in seven operated and nine outside-operated oil and gas production platforms and

200,000 acres in the Gulf of Mexico. Average net daily production from our offshore properties was 34 MMcfe per day in 2000.

*Texas State Waters.* We own an average 80% working interest in more than 50,000 gross acres in the Texas State Waters area. In addition, we have acquired 3,000 square miles of 3D seismic data in this offshore area. We have identified several exploration prospects in the shallow waters offshore in the Gulf of Mexico, at least two of which we plan to drill in 2001.

*High Island 45.* High Island Block 45 is located in shallow federal waters, offshore Texas. We are the operator and own an 83% working interest in this block which produces from the Lower Miocene sands at an approximate depth of 11,000 feet. This platform averaged net daily production of 11 MMcfe during 2000.

**Reserves**

The following table presents the estimated net quantities of our proved and proved developed reserves, and the estimated future net revenues, and the estimated present values attributable to total proved reserves for each of the preceding five years.

| **PROVED RESERVES** | **As of December 31,** | | | | |
|---|---|---|---|---|---|
| | **2000** | **1999** | **1998** | **1997** | **1996** |
| | *(dollars in millions, except price data)* | | | | |
| **Estimated Proved Reserves:** | | | | | |
| Natural gas (Bcf) | 1,608.5 | 1,294.0 | 1,193.7 | 1,028.8 | 849.2 |
| Oil (MMBbls) | 33.3 | 28.4 | 24.4 | 29.1 | 23.5 |
| Total (Bcfe) | 1,808.0 | 1,464.3 | 1,340.2 | 1,203.4 | 990.2 |
| Estimated future net revenue | $ 8,018.9 | $ 2,136.0 | $ 1,676.8 | $ 1,926.0 | $ 2,643.8 |
| Present value discounted at 10% | $ 3,734.0 | $ 1,049.7 | $ 811.1 | $ 1,002.6 | $ 1,303.7 |
| **Estimated Proved Developed Reserves:** | | | | | |
| Natural gas (Bcf) | 1,313.6 | 1,064.7 | 1,026.8 | 899.2 | 709.7 |
| Oil (MMBbls) | 27.9 | 23.9 | 20.7 | 24.3 | 17.9 |
| Total (Bcfe) | 1,481.0 | 1,208.4 | 1,151.2 | 1,045.1 | 817.1 |
| **Year-end Prices used in Estimating Future Net Revenues:** | | | | | |
| Natural gas (per Mcf) | $ 6.07 | $ 2.19 | $ 2.07 | $ 2.49 | $ 3.82 |
| Oil (per Bbl) | $ 25.38 | $ 24.36 | $ 9.46 | $ 16.76 | $ 24.70 |

No estimates of our proved reserves comparable to those included herein have been included in reports to any federal agency other than the Securities and Exchange Commission.

Our estimated proved reserves as of December 31, 2000 are based upon studies prepared by our staff of engineers and reviewed by Ryder Scott Company, independent petroleum engineers. Estimated recoverable proved reserves have been determined without regard to any economic impact that may result from our fixed-price contracts. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with Securities and Exchange Commission guidelines. The estimated future net revenues and present values were based on the engineers' production volume estimates as of each year-end. The amounts shown do not give effect to indirect expenses such as general and administrative expenses, debt service and future income tax expense or to depletion, depreciation and amortization.

The significant increase in estimated future net revenues and present value as of December 31, 2000 primarily resulted from a 177% increase in year-end natural gas prices. We estimate that if all other factors (including the estimated quantities of economically recoverable reserves) were held constant, a $1.00 per Bbl change in oil prices and a $.10 per Mcf change in gas prices from those used in calculating the present value of future net revenues would change the present value by $16 million and $67 million, respectively.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve information shown is estimated. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, the precision of the engineering and geological interpretation, and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the Securities and Exchange Commission, and are inherently imprecise. Actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. A reduction in oil and gas prices not only would reduce the value of any proved reserves, but also might reduce the amount of oil and gas that could be economically produced, thereby reducing the quantity of reserves. Our reserves and future cash flows may be subject to revisions, based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse affect on our financial condition and operating results.

For further information on reserves, future net revenues and the standardized measure of discounted future net cash flows, see Note 13 of the Notes to Consolidated Financial Statements appearing elsewhere in this document.

**Costs Incurred and Drilling Results**

The following table presents certain information regarding the costs incurred in our acquisition, exploration and development activities for each of the preceding five years.

| **COSTS INCURRED** | **As of December 31,** | | | | |
|---|---|---|---|---|---|
| | **2000** | **1999** | **1998** | **1997** | **1996** |
| | | | *(in thousands)* | | |
| Property acquisition costs: (1) | | | | | |
| Proved | $ 167,714 | $ 36,881 | $ 4,088 | $ 349,037 | $ 36,125 |
| Unproved | 18,375 | 10,766 | 11,815 | 109,648 | 6,934 |
| | 186,089 | 47,647 | 15,903 | 458,685 | 43,059 |
| Exploration costs | 23,729 | 19,409 | 74,123 | 21,514 | 10,610 |
| Development costs | 196,741 | 116,597 | 136,462 | 122,402 | 80,553 |
| Total | $ 406,559 | $ 183,653 | $ 226,488 | $ 602,601 | $ 134,222 |

(1) - Proved and unproved property acquisition costs for 1997 include $339.9 million and $98.0 million, respectively, of allocated American Exploration acquisition purchase price.

Proceeds from the sale of oil and gas properties for this same five-year period were as follows: 2000: $11.2 million; 1999: $12.4 million; 1998: $14.3 million; 1997: $27.7 million; and 1996: $.7 million.

We drilled or participated in the drilling of wells as set out in the table below for the periods indicated.

| WELLS DRILLED | Years Ended December 31, | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2000 | | 1999 | | 1998 | | 1997 | | 1996 | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Development wells: | | | | | | | | | | |
| Gas | 408 | 280 | 191 | 156 | 237 | 153 | 223 | 166 | 179 | 130 |
| Oil | 18 | 11 | 5 | 2 | 60 | 37 | 52 | 20 | 92 | 19 |
| Dry | 26 | 20 | 17 | 12 | 27 | 20 | 20 | 14 | 9 | 5 |
| Total | 452 | 311 | 213 | 170 | 324 | 210 | 295 | 200 | 280 | 154 |
| Exploratory wells: | | | | | | | | | | |
| Gas | 5 | 2 | 13 | 8 | 13 | 8 | 32 | 24 | 18 | 6 |
| Oil | -- | -- | 1 | 1 | 1 | 1 | 4 | 3 | -- | -- |
| Dry | 4 | 3 | 2 | 2 | 13 | 9 | 12 | 9 | 7 | 2 |
| Total | 9 | 5 | 16 | 11 | 27 | 18 | 48 | 36 | 25 | 8 |

As of December 31, 2000 we were involved in the drilling, testing or completing of 14 gross (8 net) development wells. No exploratory wells were in progress at December 31, 2000.

**Acreage**

The following table presents our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2000. Excluded is acreage in which our interest is limited to royalty, overriding royalty and other similar interests.

| ACREAGE | Developed | | Undeveloped | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Core Area: | | | | |
| Permian | 769,147 | 335,794 | 580,053 | 224,628 |
| Mid-Continent | 567,207 | 298,740 | 385,277 | 156,448 |
| Gulf Coast | 234,499 | 85,453 | 218,436 | 129,114 |
| Total | 1,570,853 | 719,987 | 1,183,766 | 510,190 |

**Productive Well Summary**

The following table presents our ownership in productive wells at December 31, 2000. Gross oil and gas wells include 172 wells with multiple completions. Wells with multiple completions are counted only once for purposes of the following table.

| PRODUCTIVE WELLS | Productive Wells | |
|---|---|---|
| | Gross | Net |
| Gas | 6,272 | 3,227 |
| Oil | 3,691 | 778 |
| Total | 9,963 | 4,005 |

**Title to Properties**

We believe that we have satisfactory title to our properties in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of our properties. We perform extensive title review in connection with acquisitions of proved reserves and have obtained title opinions on substantially all of our material producing properties. As is customary in the oil and gas industry, only a perfunctory title examination is performed in connection with acquisition of leases covering undeveloped properties. Generally, prior to drilling a well, a more thorough title examination of the drill site tract is conducted and curative work is performed with respect to significant title defects, if any, before proceeding with operations.

Our oil and gas properties are subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and gas industry. Except as otherwise indicated, all information presented herein is presented net of such interests. Our properties are also subject to liens for current taxes not yet due and other encumbrances. We believe that such burdens do not materially detract from the value of such properties or from the respective interests therein or materially interfere with their use in the operation of the business.

### Item 3 -- LEGAL PROCEEDINGS

We are one of numerous defendants in several lawsuits originally filed in 1995, subsequently consolidated with related litigation, and now pending in the Texas 93rd Judicial District Court in Hildago County, Texas. The lawsuit alleges that the plaintiffs, a group of local landowners and businesses, have suffered damages including, but not limited to, property damage and lost profits of approximately $60 million as the result of an underground hydrocarbon plume within the city of McAllen, Texas. The lawsuit alleges that gas wells and related pipeline facilities owned and operated by us, and other facilities operated by other defendants, caused the plume. In August 1999, the plaintiffs' experts produced reports that suggested we might be considered a significant contributor to the plume. Our investigation into this matter has not found any leaks or discharges from our facilities. In addition, our investigation has revealed the plume to be unrelated to our gas wells and facilities. Trial is not anticipated to commence until the second half of 2001. We will vigorously defend our interests in this case. We do not expect the ultimate outcome of the case to have a material adverse impact on our financial position or results of operations; however, results of litigation are inherently unpredictable and this estimate may change in the future.

We were a defendant in various other legal proceedings as of December 31, 2000 which are routine and incidental to our business. We will vigorously defend our interests in these proceedings. While the ultimate results of all these proceedings cannot be predicted with certainty, we do not believe that the outcome of these matters will have a material adverse effect on our financial position or results of operations.

### Item 4 -- SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

During the quarter ended December 31, 2000, no matters were submitted by us to a vote of security holders.

## PART II

### Item 5 -- MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock is listed on the New York Stock Exchange and traded under the symbol "LD." As of February 22, 2001, we estimate there were approximately 11,000 beneficial owners of our common stock. The high and low sales prices for our common stock during each quarter in the years ended December 31, 2000 and 1999, were as follows:

| **COMMON STOCK MARKET PRICES** | **2000** | | **1999** | |
|---|---|---|---|---|
| | **High** | **Low** | **High** | **Low** |
| **Quarter:** | | | | |
| First | $ 34.00 | $ 15.75 | $ 15.75 | $ 11.06 |
| Second | 35.00 | 24.00 | 22.00 | 14.25 |
| Third | 40.13 | 25.19 | 23.31 | 18.88 |
| Fourth | 48.19 | 29.94 | 21.50 | 16.00 |

We have paid no dividends, cash or otherwise, subsequent to the date of the initial public offering of the common stock in November 1993. Certain provisions of the indenture agreement for our 9¼% Senior Subordinated Notes due 2004 restrict our ability to declare or pay cash dividends unless certain financial ratios are maintained. Although it is not currently anticipated that any cash dividends will be paid on the common stock in the foreseeable future, the Board of Directors may review our dividend policy from time to time. In determining whether to declare dividends and the amount of dividends to be declared, the Board will consider relevant factors, including our earnings, capital needs and general financial condition.

## Item 6 -- SELECTED FINANCIAL DATA

The selected financial data presented below as of December 31, 2000 and 1999, and for each of the three years ended December 31, 2000, 1999 and 1998, has been derived from, and is qualified by reference to, our audited consolidated financial statements, including the notes thereto, contained in this document beginning at page F-1. The selected financial data as of December 31, 1998, 1997 and 1996, and for the years ended December 31, 1997 and 1996, has been derived from audited consolidated financial statements previously filed with the Securities and Exchange Commission but not contained or incorporated herein. The selected financial data should be read in conjunction with our consolidated financial statements, including the associated notes, and "Item 7 -- Management's Discussion and Analysis of Financial Condition and Results of Operations."

| SELECTED FINANCIAL DATA | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 (2) | 1999 | 1998 (3) | 1997 (4) | 1996 |
| | (in thousands, except per share data) | | | | |
| **Statement of Operations Data:** | | | | | |
| Oil and gas sales | $ 489,703 | $ 290,878 | $ 271,575 | $ 222,016 | $ 185,558 |
| Change in derivative fair value | (15,562) | (442) | 17,346 | -- | -- |
| Other income | 3,144 | 12,170 | 4,462 | 10,901 | 3,947 |
| Total revenues | 477,285 | 302,606 | 293,383 | 232,917 | 189,505 |
| Operating costs | 86,915 | 66,039 | 66,295 | 49,169 | 44,615 |
| General and administrative | 24,144 | 23,995 | 25,971 | 18,855 | 16,325 |
| Exploration costs | 25,654 | 14,258 | 34,543 | 8,956 | 4,965 |
| Depreciation, depletion and amortization | 129,323 | 117,080 | 131,408 | 79,325 | 65,278 |
| Impairment | 10,439 | 4,877 | 52,522 | 75,198 | -- |
| Interest | 41,431 | 40,667 | 40,849 | 28,737 | 26,822 |
| Total expenses | 317,906 | 266,916 | 351,588 | 260,240 | 158,005 |
| Income (loss) before income taxes and cumulative effect of accounting change | 159,379 | 35,690 | (58,205) | (27,323) | 31,500 |
| Income tax provision (benefit) | 61,119 | 14,276 | (13,924) | (11,261) | 10,398 |
| Net income (loss) before cumulative effect of accounting change | 98,260 | 21,414 | (44,281) | (16,062) | 21,102 |
| Cumulative effect of accounting change, net of tax | -- | -- | 964 | -- | -- |
| Net income (loss) | $ 98,260 | $ 21,414 | $ (43,317) | $ (16,062) | $ 21,102 |
| Net income (loss) before cumulative effect of accounting change per share | $ 2.29 | $ .53 | $ (1.10) | $ (.53) | $ .76 |
| Cumulative effect of accounting change per share | -- | -- | .02 | -- | -- |
| Net income (loss) per share - diluted | $ 2.29 | $ .53 | $ (1.08) | $ (.53) | $ .76 |
| Weighted average basic common shares | 41,830 | 40,153 | 40,107 | 30,233 | 27,800 |
| Weighted average diluted common shares | 42,836 | 40,389 | 40,107 | 30,233 | 27,810 |
| **Statement of Cash Flows Data:** | | | | | |
| Net cash provided by operating activities | $ 277,953 | $ 181,556 | $ 147,438 | $ 129,846 | $ 101,761 |
| Net cash used in investing activities | 399,581 | 167,662 | 215,274 | 216,603 | 150,857 |
| Net cash provided by (used in) financing activities | 114,767 | (6,773) | 64,837 | 84,546 | 55,261 |
| EBITDAX (1) | 381,788 | 213,014 | 183,771 | 164,893 | 128,565 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 (2) | 1999 | 1998 (3) | 1997 (4) | 1996 |
| | (in thousands) | | | | |
| **Balance Sheet Data:** | | | | | |
| Oil and gas properties, net | $ 1,340,493 | $ 1,104,804 | $ 1,064,206 | $ 1,077,091 | $ 652,257 |
| Total assets | 1,501,965 | 1,227,087 | 1,283,808 | 1,210,954 | 733,613 |
| Long-term debt, including current portion | 606,909 | 555,222 | 596,844 | 563,344 | 343,907 |
| Stockholders' equity | 532,819 | 498,782 | 519,461 | 469,204 | 263,693 |

(1) - See "Item 1 -- Business -- Certain Definitions."

(2) - We closed the acquisition of oil and gas properties from Costilla Energy Inc. in June 2000.

(3) - We adopted SFAS 133 in October 1998. See Note 1 of the Notes to Consolidated Financial Statements appearing elsewhere in this document.

(4) - We closed the acquisition of American Exploration in October 1997.

## Item 7 -- MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Overview

*General.* Our business strategy is to generate strong and consistent growth in reserves, production, operating cash flows and earnings through a program of exploration and development drilling and strategic acquisitions of oil and gas properties. Over the five-year period ended December 31, 2000, this strategy has resulted in a 106% increase in proved reserves to 1.8 Tcfe, a 123% increase in oil and gas production to 137 Bcfe, 211% growth in cash flows from operating activities to $278.0 million, and a 792% increase in net earnings to $98.3 million. All of these measures for 2000 represent record performance for us. The growth achieved during 2000 was the result of a capital program that included $238.9 million in drilling activities and $167.7 million in proved reserve acquisitions.

During the five-year period ended December 31, 2000, we drilled 1,689 gross (1,123 net wells), with an overall drilling success rate of 92%, adding 971 Bcfe of reserves (including revisions of previous estimates) to our proved reserve base. The year ended December 31, 2000 marked the seventh consecutive year that we replaced our production through our drilling activities. The 2000 drilling program added 278 Bcfe of proved reserves at an all-in finding and development cost (total costs incurred to explore and develop oil and gas properties divided by proved reserves added through extensions and discoveries and revisions of previous estimates) of $.86 per Mcfe. This addition represented 203% production replacement for 2000. We have increasingly emphasized exploration as an integral component of our business strategy and in that connection, have incurred substantial up-front costs, including significant acreage positions, seismic costs and other geological and geophysical costs. During 2000, we invested $39 million in connection with exploration activities, resulting in the acquisition of $22 million of acreage and seismic information, and the drilling of nine exploratory wells, of which five were completed as producers.

A substantial portion of our growth has been the result of proved reserve acquisitions geographically concentrated in our core operating areas where we have significant expertise and where we benefit from operational synergies. During the five-year period ended December 31, 2000, we made proved reserve acquisitions aggregating 562 Bcfe, purchased for a total consideration of $594 million, or $1.06 per Mcfe. Of particular significance was the acquisition of oil and gas properties from Costilla Energy, Inc. in 2000, which added 135 Bcfe of proved reserves, and the acquisition of American Exploration in October 1997, which added 217 Bcfe of proved reserves and an attractive unproved acreage position.

As of December 31, 2000, our portfolio of fixed-price contracts hedge 82 Bcf of future gas production in 2001, and 120 Bcf thereafter, at escalating fixed prices. The average fixed prices in these contracts are lower than the forward market prices for natural gas as of December 31, 2000. For the year ending December 31, 2001, our fixed-price natural gas swaps hedge approximately 32 Bcf of gas production at an average fixed price of $4.90 per MMBtu. Our fixed-price natural gas delivery contracts hedge approximately 18 Bcf of gas production in 2001 at an average fixed price of $2.38 per MMBtu. Our fixed-price natural gas collars hedge approximately 32 Bcf of gas production in 2001 at an average floor price of $4.57 per MMBtu and an average ceiling price of $6.28 per MMBtu. Historically, we have been an active hedger of our commodity price risk, hedging a portion of our future production out as far as 2017. Over the past few years, competition in fixed-price contracts has increased, opportunities for attractive long-term fixed-price contracts have diminished and prices in the forward market beyond one year are considerably lower than the nearby year. In response to these changes, a progressively smaller share of our production and reserve growth has been hedged due to our belief that longer-term demand and supply fundamentals for natural gas imply the potential for continued strength in natural gas prices. More recent hedging activity has been for shorter periods of time, generally less than 12 months, when market conditions have been viewed as favorable. We may decide to hedge a greater or smaller share of production in the future depending upon market conditions, capital investment considerations and other factors. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts."

*Selected Operating Data.* The following table provides certain data relating to our operations.

| SELECTED OPERATING DATA | Years Ended December 31, 2000 | 1999 | 1998 | 1997 | 1996 |
|---|---|---|---|---|---|
| **Oil and Gas Sales (M$):** | | | | | |
| Oil sales: | | | | | |
| Wellhead | $ 82,916 | $ 51,361 | $ 42,604 | $ 40,680 | $ 39,372 |
| Effect of fixed-price contract settlements (1) | (5,155) | (1,672) | 2,159 | 803 | (3,198) |
| Total | $ 77,761 | $ 49,689 | $ 44,763 | $ 41,483 | $ 36,174 |
| Natural gas sales: | | | | | |
| Wellhead | $ 469,046 | $ 237,976 | $ 205,822 | $ 185,623 | $ 148,244 |
| Effect of fixed-price contract settlements (1) | (57,104) | 3,213 | 20,990 | (5,090) | 1,140 |
| Total | $ 411,942 | $ 241,189 | $ 226,812 | $ 180,533 | $ 149,384 |
| **Production:** | | | | | |
| Oil production (MBbls) | 2,860 | 2,965 | 3,430 | 2,088 | 1,849 |
| Natural gas production (MMcf) | 119,855 | 107,979 | 101,066 | 71,731 | 63,910 |
| Equivalent production (MMcfe) | 137,015 | 125,769 | 121,647 | 84,262 | 75,004 |
| Oil production hedged by fixed-price contracts (MBbls) | 1,156 | 569 | 539 | 686 | 1,241 |
| Gas production hedged by fixed-price contracts (BBtu) | 53,119 | 59,534 | 50,823 | 43,185 | 32,508 |
| **Average Sales Price:** | | | | | |
| Oil price (per Bbl): | | | | | |
| Wellhead price | $ 28.99 | $ 17.32 | $ 12.42 | $ 19.48 | $ 21.29 |
| Effect of fixed-price contract settlements (1) | (1.80) | (.56) | .63 | .38 | (1.73) |
| Total | $ 27.19 | $ 16.76 | $ 13.05 | $ 19.86 | $ 19.56 |
| Average fixed price provided by fixed-price contracts | $ 24.36 | $ 21.64 | $ 17.37 | $ 21.81 | $ 19.53 |
| Natural gas price (per Mcf): | | | | | |
| Wellhead price | $ 3.91 | $ 2.20 | $ 2.03 | $ 2.59 | $ 2.32 |
| Effect of fixed-price contract settlements (1) | (.47) | .03 | .21 | (.07) | .02 |
| Total | $ 3.44 | $ 2.23 | $ 2.24 | $ 2.52 | $ 2.34 |
| Average fixed price provided by fixed-price contracts | $ 2.77 | $ 2.47 | $ 2.60 | $ 2.51 | $ 2.43 |
| Natural gas equivalent price (per Mcfe) | $ 3.57 | $ 2.31 | $ 2.23 | $ 2.63 | $ 2.47 |
| **Expenses and Costs Incurred (per Mcfe):** | | | | | |
| Lease operating expenses | $ .41 | $ .41 | $ .44 | $ .45 | $ .47 |
| Production taxes | .22 | .12 | .11 | .14 | .12 |
| General and administrative | .18 | .19 | .21 | .22 | .22 |
| Depreciation, depletion and amortization - oil and gas properties (2) | .91 | .89 | 1.04 | .88 | .82 |
| Finding cost (3) | .84 | .70 | .85 | 1.81 | .71 |

(1) - "Effect of fixed-price contract settlements" represents the realized hedging results from our fixed-price contracts. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts." These amounts do not include the change in derivative fair value reported in results of operations for 2000, 1999 and 1998.

(2) - Does not include impairments. See "-- Results of Operations -- Fiscal Year 2000 Compared to Fiscal Year 1999" and "-- Results of Operations -- Fiscal Year 1999 Compared to Fiscal Year 1998."

(3) - See "Item 1 -- Business -- Certain Definitions." Amounts for 1997 include the allocated purchase price of the American Exploration acquisition pursuant to purchase accounting rules.

The following table presents certain information regarding our proved oil and gas reserves.

| OIL AND GAS RESERVES DATA | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2000 | 1999 | 1998 | 1997 | 1996 |
| | (dollars in millions) | | | | |
| **Estimated Net Proved Reserves:** | | | | | |
| Natural gas (MMcf) | 1,608,469 | 1,294,029 | 1,193,666 | 1,028,752 | 849,199 |
| Oil (MBbls) | 33,258 | 28,372 | 24,416 | 29,109 | 23,497 |
| Total (MMcfe) | 1,808,018 | 1,464,258 | 1,340,161 | 1,203,405 | 990,179 |
| Reserve replacement ratio (1) | 352% | 207% | 219% | 396% | 254% |
| Reserve life (in years) (1) (2) | 13.2 | 11.6 | 11.0 | 10.7 | 13.2 |
| Estimated future net revenues (1) (3) | $ 8,018.9 | $ 2,136.0 | $ 1,676.8 | $ 1,926.0 | $ 2,643.8 |
| Present value (1) (3) | $ 3,734.0 | $ 1,049.7 | $ 811.1 | $ 1,002.6 | $ 1,303.7 |

(1) - See "Item 1 -- Business -- Certain Definitions."
(2) - For 1997, pro forma production for the American Exploration acquisition of 113.0 Bcfe was used in the reserve life determination.
(3) - Estimated future net revenues and present values give no effect to our portfolio of fixed-price contracts or federal or state income taxes attributable to estimated future net revenues. See "Item 2 -- Properties -- Reserves."

**Results of Operations -- Fiscal Year 2000 Compared to Fiscal Year 1999**

*Net Income and Cash Flows from Operating Activities.* We reported net income of $98.3 million, or $2.29 per share, on total revenue of $477.3 million for the year ended December 31, 2000. This compares to net income of $21.4 million, or $.53 per share, on total revenue of $302.6 million for 1999. Net income excluding the non-cash impact of SFAS 133 derivative accounting and nonrecurring impairment charges was $114.3 million, or $2.67 per share, for the year ended December 31, 2000 and $24.6 million, or $.61 per share, for 1999. Cash flows from operating activities before working capital changes for 2000 grew 96% to $337.4 million compared to $171.8 million for 1999. Cash flows provided by operating activities after consideration for the change in working capital were $278.0 million, which compares to $181.6 million for 1999. The significant increase in earnings and operating cash flows between the two periods was principally the result of higher oil and gas prices and higher gas production.

*Production.* Total production for the year ended December 31, 2000 grew 9%, to 137.0 Bcfe, compared to 125.8 Bcfe produced during 1999. Natural gas production for 2000 was 119.9 Bcf, an 11% increase over the 108.0 Bcf produced in 1999. Oil production in 2000 decreased 4% to 2.9 MMBbls compared to 3.0 MMBbls produced in 1999. The increase in total production is primarily attributable to the results of our 2000 exploration and development drilling program and proved reserve acquisitions made throughout the year.

*Oil and Gas Prices.* Our 2000 gas production yielded an average price of $3.44 per Mcf, 54% higher than 1999's average price of $2.23 per Mcf. Our average gas price was reduced $.47 per Mcf in 2000 and increased $.03 per Mcf in 1999 as a result of our hedging activities. The average oil price realized during 2000 increased 62% to $27.19 per Bbl compared to $16.76 per Bbl for 1999. Fixed-price contract settlements decreased the average oil price in 2000 by $1.80 per Bbl and decreased the average oil price in 1999 by $.56 per Bbl. On a natural gas equivalent basis, we realized an average price of $3.57 per Mcfe for 2000, a 55% increase compared to the $2.31 per Mcfe received in 1999.

The combination of higher gas production and higher average gas price for 2000 increased natural gas sales by 71% to $411.9 million, compared to $241.2 million reported for 1999. The net effect of higher oil prices and lower oil production resulted in a 56% increase in oil sales to $77.8 million, compared to $49.7 million for the prior-year period. The aggregate impact of fixed-price contract settlements during each period was a decrease in oil and gas revenues of $62.3 million in 2000 and an increase in oil and gas revenues of $1.5 million in 1999. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts."

*Change in Derivative Fair Value.* We recognized losses in change in derivative fair value of $15.6 million and $.4 million for the years ended December 31, 2000 and 1999, respectively. Amounts recorded in this caption represent non-cash gains and losses created by temporary valuation swings in derivatives or portions of derivatives which are not entitled to receive hedge accounting treatment. All amounts recorded in this caption are ultimately reversed in this caption over the respective contract term. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts -- Accounting" for a discussion of the components recorded in this caption.

*Other Income.* We realized other income for 2000 of $3.1 million compared to $12.2 million for 1999. The amount for 1999 included a nonrecurring pretax gain of $8.6 million recognized upon the settlement of certain litigation.

*Operating Costs.* Operating costs for 2000 were comprised of $56.3 million of lease operating expenses and $30.6 million of production taxes. This compares to $51.2 million of lease operating expenses and $14.8 million of production taxes for 1999. The increase in lease operating expenses is principally attributable to the costs associated with acquired properties, in particular the Costilla properties, and wells drilled during the year. On a natural gas equivalent unit of production basis, lease operating expenses remained constant in 2000 at $.41 per Mcfe in relation to 1999. The increase in production taxes in 2000 is attributable to higher oil and gas prices and higher gas production.

*General and Administrative Expense.* General and administrative expense, or G&A, for 2000 increased modestly to $24.1 million compared to $24.0 million for 1999. This limited increase is primarily the result of increases in overhead recoveries associated with a more active drilling program, which largely offset cost increases during the year. As a result, G&A per natural gas equivalent unit of production improved to $.18 per Mcfe for 2000 compared to $.19 per Mcfe for 1999.

*Exploration Costs.* Exploration costs, comprised of geological and geophysical costs, or G&G costs, exploratory dry hole costs, and leasehold impairment costs, were $25.7 million for the year ended December 31, 2000 compared to $14.3 million for the year ended December 31, 1999. The 2000 amount consisted of $5.8 million of seismic acquisition and other G&G costs, $11.0 million of dry hole costs and $8.9 million of leasehold impairments. The 1999 amount consisted of $5.0 million of G&G costs, $1.2 million of dry hole costs and $8.1 million of leasehold impairments.

*Depreciation, Depletion and Amortization.* Depreciation, depletion and amortization expense, or DD&A, for the year ended December 31, 2000 was $129.3 million compared to $117.1 million for 1999. This increase is due to an increase in the oil and gas DD&A rate for 2000 and an increase in gas production. The oil and gas DD&A rate per equivalent unit of production was $.91 per Mcfe for 2000 compared to $.89 per Mcfe in 1999. The DD&A rate increased primarily as a result of production increases in certain higher cost fields and the cost of the Costilla acquisition.

*Impairment.* We recorded total impairment charges of $10.4 million during 2000 primarily as a result of downward reserve revisions for two single-well offshore fields. Overall for 2000, we realized net upward reserve revisions of approximately 2 Bcfe. In 1999, we recognized impairment charges totaling $4.9 million, also primarily the result of downward reserve revisions for certain offshore fields. For 1999, we reported net upward reserve revisions of approximately 12 Bcfe.

For purposes of determining whether oil and gas properties have been impaired, we utilize forward market price quotations as of the date of determination in estimating the future cash flows from our oil and gas properties. This forward market price information is consistent with that generally used by us in making drilling and acquisition plans and decisions. In the impairment calculation, these market prices for future periods are used to price the estimated production from proved reserves for the corresponding periods in arriving at future cash flows. No changes in production from the profile included in the year-end reserve report are assumed.

*Interest Expense.* Interest expense for 2000 was $41.4 million which compares to $40.7 million for 1999. The 2000 increase is primarily due to higher average debt balances outstanding during the year, principally the result of the Costilla acquisition. The net impact of interest rate swap settlements for the year ended December 31, 2000 decreased interest expense by $1.9 million. The impact of interest rate swap settlements in 1999 was not material. See "-- Item 7A - Quantitative and Qualitative Disclosures About Market Risk -- Interest Rate Sensitivity."

*Income Taxes.* For 2000, we recorded a tax provision of $61.1 million on pretax income of $159.4 million, an effective rate of 38%. This compares to a tax provision of $14.3 million, or 40%, on pretax income of $35.7 million for 1999. The effective rate for 1999 varied from the statutory rate due to permanent differences related to the tax bases of certain acquired oil and gas properties.

**Results of Operations -- Fiscal Year 1999 Compared to Fiscal Year 1998**

*Net Income (Loss) and Cash Flows from Operating Activities.* We reported net income of $21.4 million, or $.53 per share, on total revenue of $302.6 million for the year ended December 31, 1999. This compares to a net loss of $43.3 million, or $1.08 per share, on total revenue of $293.4 million for 1998. Cash flows from operating activities before working capital changes for 1999 grew 19% to $171.8 million compared to $144.9 million for 1998. Cash flows provided by operating activities after consideration for the change in working capital was $181.6 million, which compares to $147.4 million for 1998. The significant increase in earnings and operating cash flows between the two periods was principally the result of cost improvements realized during 1999, higher oil and gas sales resulting from gas production growth and higher oil prices, and a nonrecurring pretax gain of $8.6 million recognized upon the settlement of certain litigation. Earnings for 1998 were adversely affected by non-cash impairment charges totaling $52.5 million ($34.1 million after tax or $.85 per share), resulting primarily from significantly lower oil and gas prices.

*Production.* Total production for the year ended December 31, 1999 grew 3%, to 125.8 Bcfe, compared to 121.6 Bcfe produced during 1998. Natural gas production for 1999 was 108.0 Bcf, a 7% increase over the 101.1 Bcf produced in 1998. Oil production in 1999 decreased 14% to 3.0 MMBbls compared to 3.4 MMBbls produced in 1998. The increase in total production is primarily attributable to the results of our 1999 net capital expenditure program which was funded solely through cash flows from operating activities.

*Oil and Gas Prices.* Our 1999 gas production yielded an average price of $2.23 per Mcf, slightly lower than 1998's average price of $2.24 per Mcf. Our average gas price was enhanced $.03 per Mcf in 1999 and $.21 per Mcf in 1998 as a result of our hedging activities. The average oil price received during 1999 increased 28% to $16.76 per Bbl compared to $13.05 per Bbl for 1998. Fixed-price contract settlements decreased the average oil price in 1999 by $.56 per Bbl and increased the average oil price in 1998 by $.63 per Bbl. On a natural gas equivalent basis, we realized an average price of $2.31 per Mcfe for 1999, a 4% increase compared to the $2.23 per Mcfe received in 1998.

The combination of higher gas production and lower average gas price for 1999 increased gas sales by 6% to $241.2 million, compared to $226.8 million reported for 1998. The combined effect of higher oil prices and lower oil production was an 11% increase in oil sales to $49.7 million, compared to $44.8 million for the prior-year period. The aggregate impact of fixed-price contract settlements during each period was an increase in oil and gas revenues of $1.5 million in 1999 and an increase in oil and gas revenues of $23.1 million in 1998. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts."

*Change in Derivative Fair Value.* We recognized a loss in change in derivative fair value of $.4 million in 1999 and a gain of $17.3 million in 1998. Amounts recorded in this caption represent non-cash gains and losses created by temporary valuation swings in derivatives or portions of derivatives which are not entitled to receive hedge accounting treatment. All amounts recorded in this caption are ultimately reversed in this caption over the respective contract term. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts -- Accounting" for a discussion of the components recorded in this caption.

*Other Income (Loss).* We realized other income for 1999 of $12.2 million compared to $4.5 million for 1998. The 1999 increase was primarily the result of a nonrecurring pretax gain of $8.6 million recognized upon the settlement of certain litigation.

*Operating Costs.* Operating costs for 1999 were comprised of $51.2 million of lease operating expenses and $14.8 million of production taxes. This compares to $53.2 million of lease operating expenses and $13.1 million of production taxes for 1998. The decrease in lease operating expenses is principally attributable to improved operating efficiencies in the field and to a reduction in costs for services and materials. On a natural gas equivalent unit of production basis, lease operating expenses improved to $.41 per Mcfe compared to $.44 for 1998. The increase in production taxes in 1999 is attributable to higher production and higher oil prices.

*General and Administrative Expense.* G&A for 1999 was $24.0 million compared to $26.0 million for 1998. This decrease is primarily attributable to cost reduction measures implemented by us in the first quarter of 1999. As a result, G&A per natural gas equivalent unit of production improved to $.19 per Mcfe for 1999 compared to $.21 per Mcfe for 1998.

*Exploration Costs.* Exploration costs, comprised of G&G costs, exploratory dry hole costs and leasehold impairment costs, were $14.3 million for the year ended December 31, 1999 compared to $34.5 million for the year ended December 31, 1998. The 1999 amount consisted of $5.0 million of G&G costs, $1.2 million of dry hole costs and $8.1 million of leasehold impairments. The 1998 amount consisted of $12.8 million of G&G costs, $16.5 million of dry hole costs and $5.2 million of leasehold impairments.

*Depreciation, Depletion and Amortization.* DD&A for the year ended December 31, 1999 was $117.1 million compared to $131.4 million for 1998. This decrease is due to a decrease in the oil and gas DD&A rate for 1999. The oil and gas DD&A rate per equivalent unit of production was $.89 per Mcfe for 1999 compared to $1.04 per Mcfe in 1998. The DD&A rate improved primarily as a result of 1999 proved reserve additions added at a finding cost of $.70 per Mcfe, and the impairment charge recorded in the fourth quarter of 1998.

*Impairment.* We recorded total impairment charges of $4.9 million during 1999 primarily as a result of downward reserve revisions for certain offshore fields. Overall for 1999, we reported net upward reserve revisions of approximately 12 Bcfe. In 1998, we recognized impairment charges totaling $52.5 million, primarily as a result of a significant decline in oil and gas prices in the fourth quarter of 1998.

For purposes of determining whether oil and gas properties have been impaired, we utilize forward market price quotations as of the date of determination in estimating the future cash flows from our oil and gas properties. This forward market price information is consistent with that generally used by us in making drilling and acquisition plans and decisions. In the impairment calculation, these market prices for future periods are used to price the estimated production from proved reserves for the corresponding periods in arriving at future cash flows. No changes in production from the profile included in the year-end reserve report are assumed.

*Interest Expense.* Interest expense for 1999 was $40.7 million which compares to $40.8 million for 1998. The net impact of interest rate swap settlements for the years ended December 31, 1999 and 1998 was immaterial. See "-- Item 7A - Quantitative and Qualitative Disclosures About Market Risk -- Interest Rate Sensitivity."

*Income Taxes.* For 1999, we recorded a tax provision of $14.3 million on pretax income of $35.7 million, an effective rate of 40%. This compares to a tax benefit of $13.9 million, or 24%, on a pretax loss of $58.2 million for 1998. The effective rates for both 1999 and 1998 varied from the statutory rate due to permanent differences related to the tax bases of certain acquired oil and gas properties. The effective tax rate for 1998 includes the effect of an adjustment to the net operating loss carryforward valuation allowance.

*Cumulative Effect of Accounting Change.* In the fourth quarter of 1998, we adopted the provisions of SFAS 133 which established new accounting and reporting guidelines for derivative instruments and hedging activities. This caption includes the cumulative adjustments to results of operations related to adopting this standard of $1.6 million, shown net of tax of $.6 million. See Note 1 of the Notes to Consolidated Financial Statements appearing elsewhere in this document.

**Capital Resources and Liquidity**

*Cash Flows.* Our business of acquiring, exploring and developing oil and gas properties is capital intensive. Our ability to grow our reserve base is contingent, in part, upon our ability to generate cash flows from operating activities and to access outside sources of capital to fund investing activities. For the three years ended December 31, 2000, 1999 and 1998, our cash flows related to investing activities included net investments of $395.1 million, $165.9 million and $212.6 million, respectively, in oil and gas property acquisition, exploration and development activities. We currently anticipate spending approximately $290 million in exploration and development activities in 2001. Variations in capital expenditure levels over the three-year period are primarily tied to the amount of proved property acquisitions made in each year. See "-- Commitments and Capital Expenditures." Certain of these drilling investments include expenditures which under successful efforts accounting are expensed as incurred or if unsuccessful in discovering new reserves. Investing activities for the years ended December 31, 2000, 1999 and 1998, include $17.8 million, $6.6 million and $30.5 million, respectively, of costs which have been expensed as exploration costs in the statement of operations for the corresponding periods. For the three-year period, cash flows from operating activities were $278.0 million, $181.6 million and $147.4 million, representing 70%, 109% and 69%, respectively, of the net cash oil and gas property investments made in each year. Substantially all of the cash flows from operating activities are generated from oil and gas sales which are highly dependent upon oil and gas prices. Significant decreases in the market prices of oil or gas could result in reductions of cash flows from operating activities, which in turn could impact the amount of capital investment. A portion of this price risk and cash flow volatility has been hedged by fixed-price contracts. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts." The growth achieved in cash flows from operating activities over this period is discussed under "-- Results of Operations -- Fiscal Year 2000 Compared to Fiscal Year 1999" and "-- Results of Operations -- Fiscal Year 1999 Compared to Fiscal Year 1998."

Cash flows from financing activities were a significant source of funding for our investing activities in 2000 and 1998. Historically, we have relied upon availability under various revolving bank credit facilities and proceeds from the issuance of senior and subordinated notes to fund our investing activities. For the year ended December 31, 1999, we reduced our borrowings under such facilities by $41.6 million. For the two years ended December 31, 2000 and 1998, net amounts borrowed under such facilities were $58.2 million and $31.7 million, or 15% and 15%, respectively, of the net cash oil and gas investments made for each year. Our debt facilities are discussed in greater detail below. In addition, we received $44.2 and $40.1 million from the termination of two fixed-price contracts in 1999 and 1998, respectively.

In June 2000, we sold 2.4 million shares of common stock at $31.00 per share ($29.53 per share net of underwriting discount) in a public offering. Proceeds from the offering of $70.9 million received in July 2000 were applied to reduce a majority of the indebtedness incurred in connection with the acquisition of properties from Costilla Energy, Inc. In addition, an indirect wholly-owned subsidiary of S.A. Louis Dreyfus et Cie sold 1.6 million shares of our common stock in the offering. Subsequent to the offering, S.A. Louis Dreyfus et Cie through its subsidiaries owned 19.2 million common shares, or approximately 44% of the total issued and outstanding common shares.

Our EBITDAX increased to $381.8 million in 2000 from $213.0 million in 1999 and $183.8 million in 1998. EBITDAX is defined herein as income (loss) before interest, income taxes, DD&A, impairment, exploration costs and change in derivative fair value. Increases in EBITDAX have occurred primarily as a result of increases in our oil and gas sales. We believe that EBITDAX is a financial measure commonly used in the oil and gas industry as an indicator of a company's ability to service and incur debt. However, EBITDAX should not be considered in isolation or as a substitute for net income, cash flows provided by operating activities or other data prepared in accordance with generally accepted accounting principles, or as a measure of a company's profitability or liquidity. EBITDAX measures as presented herein may not be comparable to other similarly titled measures of other companies.

*$450 Million Revolving Credit Facility*. We have a revolving credit facility with a syndicate of banks which provides up to $450 million in borrowings. Letters of credit under the credit facility are limited to $75 million of this total availability. The credit facility allows us to draw on the full $450 million credit line without restrictions tied to periodic revaluations of our oil and gas reserves provided we continue to maintain an investment grade credit rating from either Standard & Poor's Ratings Service or Moody's Investors Service. We currently have senior unsecured credit ratings of BBB and Baa3 from Standard & Poor's and Moody's, respectively. A borrowing base can be required only upon the vote by a majority in interest of the lenders after the loss of an investment grade credit rating. No principal payments are required under the credit facility prior to maturity on October 14, 2002. We have relied upon the credit facility to provide funds for acquisitions and to provide letters of credit to meet our margin requirements under fixed-price contracts. See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts." As of December 31, 2000, we had $300.6 million of principal and $71.6 million of letters of credit outstanding under the credit facility.

We have the option of borrowing at a LIBOR-based interest rate or the base rate (approximating the prime rate). The LIBOR interest rate margin and the facility fee payable under the credit facility are subject to a sliding scale based on our senior debt credit rating. At December 31, 2000 the applicable interest rate was LIBOR plus 23 basis points. The credit facility also requires the payment of a facility fee equal to 12 basis points of the total commitment. The average interest rate for borrowings under the credit facility was 6.9% at December 31, 2000. The effective interest rate including the effect of interest rate swaps was 6.2%.

The credit facility contains various affirmative and restrictive covenants which, among other things, limit total indebtedness to $700 million ($625 million of senior indebtedness) and require us to meet certain financial tests. Borrowings under the credit facility are unsecured.

*Other Lines of Credit.* We have certain other unsecured lines of credit available to use, which aggregated $50.1 million as of December 31, 2000. These short-term lines of credit are primarily used for working capital purposes. Borrowings under these credit lines totaled $13.2 million as of December 31, 2000. Outstanding letters of credit were immaterial. Repayment of indebtedness under these credit lines is expected to be made through the revolving bank credit facility availability.

*6 f% Senior Notes due 2007.* In December 1997, we issued $200 million principal amount, $198.8 million net of discount, of 6 f % Senior Notes due 2007. Interest is payable semi-annually on June 1 and December 1. The associated indenture agreement contains restrictive covenants which place limitations on the amount of liens and our ability to enter into sale and leaseback transactions.

*9¼% Senior Subordinated Notes due 2004.* In June 1994, we issued $100 million principal amount, $98.5 million net of discount, of 9¼% Senior Subordinated Notes due 2004. Interest is payable semi-annually on June 15 and December 15. The associated indenture agreement contains restrictive covenants which limit, among other things, the prepayment of the subordinated notes, the incurrence of additional indebtedness, the payment of dividends and the disposition of assets. We purchased $6.3 million principal amount of these notes in the open market during 2000, leaving an outstanding unpaid principal balance of $93.7 million as of December 31, 2000.

At December 31, 2000, we had a working capital deficit of $70.8 million and a current ratio of .7 to 1. This working capital deficit is the result of recording the fair value of fixed-price contract settlements scheduled to occur over the next twelve-month period based on market prices for oil and gas as of the balance sheet date, and option valuations. The offsetting increase in value of the hedged future production has not been accrued in the accompanying balance sheet, creating the appearance of a working capital deficit from the contracts. These settlement amounts are not due and payable until the monthly period that the related underlying hedged transaction occurs. In some cases, the recorded liability for certain contracts significantly exceeds the total settlement amounts that would be paid to a counterparty based on prices in effect at the balance sheet date due to option time value. Since we expect to hold these collars to maturity, this time value component has no direct relationship to actual future contract settlements and consequently does not represent a liability which will be settled in cash or realized in any way. Short-term liquidity has actually improved as a result of the increase in oil and gas prices. Excluding the current portion of fixed-price contracts from current assets and liabilities, working capital was $54.4 million and the current ratio was 1.7 to 1. Total long-term debt outstanding at December 31, 2000 was $606.9 million. Our long-term debt as a percentage of total capitalization was 53%. Debt to capitalization excluding the unrealized non-cash effects of SFAS 133 in accumulated other comprehensive income in stockholders' equity was 49%. The amount of required principal payments for the next five years and thereafter as of December 31, 2000 is as follows: 2001 - $0; 2002 - $313.8 million; 2003 - $0; 2004 - $93.7 million; 2005 - $0; thereafter - $200 million. We believe that the borrowing capacity under our existing credit facilities, combined with our internal cash flows, will be adequate to finance the capital expenditure program budgeted for 2001 and to meet our margin requirements under fixed-price contracts. See "-- Commitments and Capital Expenditures" and "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Fixed-Price Contracts -- Margin."

See "Item 7A -- Quantitative and Qualitative Disclosures About Market Risk -- Interest Rate Sensitivity" for a discussion of the interest rate swaps hedging the interest rate exposure associated with borrowings under the bank credit facility.

**Commitments and Capital Expenditures**

Our business strategy is to generate strong and consistent growth in reserves, production, operating cash flows and earnings through a program of exploration and development drilling and strategic acquisitions of oil and gas properties. For the year ended December 31, 2000, we invested $199.8 million in development activities, $39.1 million in exploration activities and $167.4 million in proved reserve acquisitions in connection with this strategy. In addition, we received $11.2 million in connection with sales of certain oil and gas properties. Our 2000 drilling program resulted in the drilling of 461 gross (316 net) wells, including nine gross (five net) exploratory wells and 452 gross (311 net) development wells. Our drilling activities added 278 Bcfe to our proved reserve base. Reserves added through 2000 acquisitions totaled 204 Bcfe.

Our approved drilling budget for 2001 provides for approximately $290 million in oil and gas exploration and development activities. Of these expenditures, approximately $226 million is targeted for development activities and

$64 million is directed to exploration activities to be conducted in our core areas. Actual levels of exploration and development expenditures may vary due to many factors, including drilling results, new drilling opportunities, drilling rig availability, oil and natural gas prices and acquisition opportunities. See "-- Outlook for 2001." We continue to actively search for attractive oil and gas property acquisitions, but are not able to predict the timing or amount of capital expenditure which may ultimately be employed in acquisitions during 2001.

In the ordinary course of our business, we may contract for drilling or other services for extended periods of time, but generally less than 12 months, or may enter into agreements for oil and gas lease acreage which require a certain level of drilling activity to maintain its lease position. Such arrangements are common to our industry.

**Outlook for Fiscal Year 2001**

*General.* The discussion of our fiscal year 2001 outlook provided under this caption and other forward-looking statements in this document reflect the current expectations of management and are based on our historical operating trends, our proved reserve and fixed-price contract positions as of December 31, 2000, and other information currently available to us. Forward-looking statements include statements regarding our future drilling plans and objectives, and related exploration and development budgets, and number and location of planned wells, and statements regarding the quality of our properties and potential reserve and production levels. These statements may be preceded or followed by, or otherwise include the words "believes", "expects", "anticipates", "intends", "plans", "estimates", "projects", or similar expressions or statements that certain events "will" or "may" occur. These statements assume, among other things, that no significant changes will occur in the operating environment for our oil and gas properties and that there will be no material acquisitions or divestitures except as disclosed in this document.

We caution that the forward-looking statements are subject to all the risks and uncertainties incident to the acquisition, exploration, development and marketing of oil and gas reserves. These risks include, but are not limited to, commodity price, counterparty, environmental, drilling, reserves, operations and production risks. Certain of these risks are described elsewhere in this document. Moreover, we may make material acquisitions or divestitures, modify fixed-price contract positions by entering into new contracts or terminating existing contracts, or enter into financing transactions. None of these can be predicted with certainty and are not taken into consideration in the forward-looking statements.

Statements concerning fixed-price contract, interest rate swap and other financial instrument fair values and their estimated contribution to future results of operations are based upon market information as of a specific date. This market information is often a function of significant judgment and estimation. Further, market prices for oil and gas and market interest rates are subject to significant volatility.

For all of these reasons, actual results may vary materially from the forward-looking statements and there is no assurance that the assumptions used are necessarily the most likely. We expressly disclaim any obligation or undertaking to release publicly any updates regarding any changes in our expectations with regard to the subject matter of any forward-looking statements or any changes in events, conditions or circumstances on which any forward-looking statements are based.

There is no assumption for proved reserve acquisitions which may be made during 2001 in the estimates provided below. Acquisitions could, depending on size, materially impact these estimates.

*Revenues.* Our drilling budget approved by the Board of Directors for 2001 is $290 million. Based on this expenditure level, the inventory of drilling opportunities identified for 2001, internal production forecasts for developed and undeveloped properties and historical finding cost results, we expect 2001 production to range from 147 Bcfe to 161 Bcfe. Gas production is expected to range from 132 Bcf to 144 Bcf. Oil production is expected to approximate 2.7 MMBbls. We expect that natural gas prices at the wellhead will average $.08 to $.12 per Mcf less than the average of the last three trading days for the NYMEX Henry Hub index (NYMEX L3D). The NYMEX L3D price for January 2001 was $9.79 per MMBtu and for February 2001 was $6.94 per MMBtu. Crude oil prices are expected to average $1.50 to $1.75 per Bbl less than the average NYMEX West Texas Intermediate price (WTI).

Approximately 50 Bcf of natural gas in 2001 is hedged by swaps and physical delivery contracts. The weighted average contract price is expected to be approximately $4.29 per Mcf before the impact of basis, including the amortization of deferred gains. Additionally, approximately 32 Bcf of gas is subject to collars with average floor prices of $4.57 per Mcf and average ceiling prices of $6.28 per Mcf. The impact of contract basis is expected to range from being neutral to having the effect of increasing the average contract price by $.03 per Mcf for hedged production. The amount of change in derivative fair value to be reported in revenues for 2001 cannot be predicted due to contract valuations and effectiveness testing which are performed at the end of each quarter throughout the year.

*Expenses.* Lease operating expenses for 2001 are expected to range from $.42 to $.44 per Mcfe. Production taxes are expected to range from 5.5% to 6.0% of wellhead sales. DD&A for 2001 is expected to range from $.95 to $.97 per Mcfe.

General and administrative costs are expected to range from $29 million to $30 million in 2001. Exploration costs could range between $25 million and $60 million, depending upon the level of investment in seismic, other geological and geophysical costs and success experienced with exploration drilling. We do not expect to recognize impairment charges in 2001; however, impairments cannot be predicted with any certainty. Interest expense is expected to range from $30 million to $33 million, but is highly dependent upon oil and gas prices and level of capital expenditures.

We expect that the effective income tax rate for 2001 will approximate 38%. The current tax provision in 2001, which is particularly susceptible to change with fluctuating commodity prices, is expected to represent between 50% and 65% of the total tax provision primarily as a result of the deduction of intangible drilling costs and utilization of acquired tax carryforwards.

## ITEM 7A -- QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### General

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas and changes in market interest rates. To mitigate a portion of this exposure to adverse market changes, we have entered into fixed-price contracts and interest rate swaps. All of our fixed-price contracts and interest rate swaps have been entered into as hedges of oil and gas price risk or interest rate risk and not for trading purposes. Information regarding our market exposures, fixed-price contracts, interest rate swaps and certain other financial instruments is provided below. All information is presented in U.S. Dollars.

### Fixed-Price Contracts

*Description of Contracts.* We utilize fixed-price contracts to reduce exposure to unfavorable changes in oil and gas prices which are subject to significant and often volatile fluctuation. Our fixed-price contracts are comprised of long-term physical delivery contracts, energy swaps, collars and basis swaps. These contracts allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. For the years ended December 31, 2000, 1999 and 1998, fixed-price contracts hedged 44%, 55% and 50%, respectively, of our gas production and 40%, 19% and 16%, respectively, of our oil production. As of December 31, 2000, fixed-price contracts are in place to hedge 82 Bcf of future gas production in 2001, and 120 Bcf thereafter.

For energy swap contracts, we receive a fixed price for the respective commodity and pay a floating market price, as defined in each contract (generally NYMEX futures prices or a regional spot market index), to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty. For physical delivery contracts, we purchase gas in the spot market at floating market prices and deliver gas to the contract counterparty at a fixed price. Natural gas collars contain a fixed floor price (put) and ceiling price (call). If the market price of natural gas exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price. If the market price of natural gas is between the call and the put strike price, then no payments are due from either party. Under the basis swaps, we receive the floating market price for NYMEX futures and pay the floating market price plus a fixed differential for a specified regional spot market index.

The following table summarizes the estimated volumes, fixed prices, fixed-price sales and future net revenues attributable to the fixed-price contracts as of December 31, 2000. We expect the prices to be realized for hedged production to vary from the prices shown in the following table due to basis, which is the differential between the floating price paid under each energy swap contract, or the cost of gas to supply physical delivery contracts, and the price received at the wellhead for our hedged production. Basis differentials are caused by differences in location, quality, contract terms, timing and other variables. Future net revenues for any period are determined as the differential between the fixed prices provided by fixed-price contracts and forward market prices as of December 31, 2000, as adjusted for basis. Future net revenues change with changes in market prices and basis. See "-- Market Risk."

| | Years Ending December 31, | | | | | Balance through | |
|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2017 | Total |
| | *(dollars in thousands, except price data)* | | | | | | |
| **Natural Gas Swaps:** | | | | | | | |
| Contract volumes (BBtu) | 32,340 | 6,697 | 5,650 | 5,650 | 5,650 | 6,483 | 62,470 |
| Weighted-average fixed price per MMBtu (1) | $ 4.90 | $ 2.65 | $ 2.92 | $ 3.12 | $ 3.32 | $ 3.41 | $ 4.02 |
| Future fixed-price sales | $ 158,579 | $ 17,766 | $ 16,492 | $ 17,608 | $ 18,740 | $ 22,082 | $ 251,267 |
| Future net revenues (2) | $ (36,849) | $ (11,542) | $ (5,028) | $ (3,276) | $ (2,089) | $ (1,901) | $ (60,685) |
| **Natural Gas Physical Delivery Contracts:** | | | | | | | |
| Contract volumes (BBtu) | 17,814 | 17,689 | 14,819 | 6,634 | 5,314 | 38,116 | 100,386 |
| Weighted-average fixed price per MMBtu (1) | $ 2.38 | $ 2.46 | $ 2.53 | $ 2.53 | $ 2.63 | $ 3.01 | $ 2.68 |
| Future fixed-price sales | $ 42,464 | $ 43,461 | $ 37,428 | $ 16,802 | $ 13,978 | $ 114,760 | $ 268,893 |
| Future net revenues (2) | $ (71,426) | $ (32,751) | $ (18,105) | $ (7,569) | $ (5,519) | $ (31,932) | $ (167,302) |
| **Natural Gas Collars:** | | | | | | | |
| Contract volumes (BBtu): | | | | | | | |
| Floor | 31,800 | 7,300 | -- | -- | -- | -- | 39,100 |
| Ceiling | 31,800 | 7,300 | -- | -- | -- | -- | 39,100 |
| Weighted-average fixed-price per MMBtu (1): | | | | | | | |
| Floor | $ 4.57 | $ 2.84 | $ -- | $ -- | $ -- | $ -- | $ 4.25 |
| Ceiling | $ 6.28 | $ 3.94 | $ -- | $ -- | $ -- | $ -- | $ 5.84 |
| Future fixed-price sales (4) | $ 145,447 | $ 20,732 | $ -- | $ -- | $ -- | $ -- | $ 166,179 |
| Future net revenues (2) | $ (16,201) | $ (3,902) | $ -- | $ -- | $ -- | $ -- | $ (20,103) |
| **Total Natural Gas Contracts (3):** | | | | | | | |
| Contract volumes (BBtu) | 81,954 | 31,686 | 20,469 | 12,284 | 10,964 | 44,599 | 201,956 |
| Weighted-average fixed price per MMBtu (1) | $ 4.23 | $ 2.59 | $ 2.63 | $ 2.80 | $ 2.98 | $ 3.07 | $ 3.40 |
| Future fixed-price sales (4) | $ 346,490 | $ 81,959 | $ 53,920 | $ 34,410 | $ 32,718 | $ 136,842 | $ 686,339 |
| Future net revenues (2) | $(124,476) | $ (48,195) | $ (23,133) | $ (10,845) | $ (7,608) | $ (33,833) | $ (248,090) |

(1) - We expect the prices to be realized for hedged production to vary from the prices shown due to basis. See "-- Market Risk."

(2) - Future net revenue amounts as presented above are undiscounted and have not been adjusted for contract performance risk or counterparty credit risk. Bracketed amounts represent decreases to future natural gas sales.

(3) - Does not include basis swaps with notional volumes by year, as follows: 2001 - 9.4 TBtu; and 2002 - 5.5 TBtu.

(4) - Assumes floor prices for natural gas collar volumes.

The estimates of future net revenues from fixed-price contracts are computed based on the difference between the prices provided by the contracts and forward market prices as of the specified date. The market for natural gas beyond a five year horizon is illiquid and published market quotations are not available. We have relied upon near-term market quotations, longer-term over-the-counter market quotations and other market information to determine future net revenue estimates. Forward market prices for natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility. The future net revenue estimates shown above are subject to change as forward market prices change.

The estimated fair value and carrying value of our fixed-price contracts as of December 31, 2000 and 1999 are provided below.

| | December 31, 2000 | | December 31, 1999 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| | (in thousands) | | | |
| **Derivative assets:** | | | | |
| Fixed-price natural gas swaps | $ -- | $ -- | $ 16,433 | $ 16,433 |
| Fixed-price natural gas collars | -- | -- | 1,323 | 1,323 |
| Fixed-price natural gas delivery contracts | -- | -- | 7,921 | 7,921 |
| Fixed-price crude oil swaps | -- | -- | 360 | 360 |
| **Derivative liabilities:** | | | | |
| Fixed-price natural gas swaps | (55,923) | (55,923) | (4,329) | (4,329) |
| Fixed-price natural gas collars | (26,054) | (26,054) | -- | -- |
| Fixed-price natural gas delivery contracts | (146,234) | (146,234) | (9,081) | (9,081) |
| Natural gas basis swaps | (1,491) | (1,491) | (3,271) | (3,271) |
| Total | $ (229,702) | $ (229,702) | $ 9,356 | $ 9,356 |

The fair value of fixed-price contracts as of December 31, 2000 and 1999 was estimated based on market prices of natural gas and crude oil for the periods covered by the contracts. The net differential between the prices in each contract and market prices for future periods, as adjusted for estimated basis, has been applied to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on a contract-by-contract basis at rates commensurate with our estimation of contract performance risk and counterparty credit risk. The fair value of derivative instruments which contain options (e.g. collar structures) has been estimated based on remaining term, volatility and other factors. The terms and conditions of our fixed-price physical delivery contracts and certain financial swaps are uniquely tailored to our circumstances. In addition, certain of the contracts hedge gas production for periods beyond five years into the future. The market for natural gas beyond the five-year horizon is illiquid and published market quotations are not available. We have relied upon near-term market quotations, longer-term over-the-counter market quotations and other market information to determine fair value estimates.

The change in carrying value of fixed-price contracts and interest rate swaps in the December 31, 2000 balance sheet compared to the December 31, 1999 balance sheet resulted from a significant increase in market prices for natural gas and an increase in interest rates. Derivative liabilities reflected as current in the December 31, 2000 balance sheet include the estimated fair value of fixed-price contract settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and gas as of the balance sheet date, and option time value. The offsetting increase in value of the hedged future production has not been accrued in the accompanying balance sheet, creating the appearance of a working capital deficit from these contracts. These contract settlement amounts are not due and payable until the monthly period that the related underlying hedged production occurs. In some cases the recorded liability for certain contracts significantly exceeds the total settlement amounts that would be paid to a counterparty based on prices in effect at the balance sheet date due to option time value. Since we expect to hold these contracts to maturity, this time value component has no direct relationship to actual future contract settlements and consequently does not represent a liability which will be settled in cash or realized in any way.

The vast majority of all fixed-price contract fair value changes are reflected in accumulated other comprehensive income on the face of the balance sheet, shown net of deferred tax effect. At December 31, 2000, this accounting treatment resulted in a cumulative unrealized reduction in stockholders' equity of $99.0 million, giving the appearance that a loss in net enterprise value was experienced as a result of increases in market oil and gas prices. Except for the effect of basis movements, we expect that any changes in fixed-price contract fair value attributable to changes in market prices for oil and natural gas will be offset by changes in the value of our oil and natural gas reserves. Because only 13% of the future production from our natural gas reserves is hedged, higher oil and gas prices actually increase our net enterprise value, as is apparent in the standardized measure calculation. This change in reserve value, however, is not reflected in our balance sheet. See Note 13 -- Supplemental

Information - Oil and Gas Reserves appearing elsewhere in this document.

*Accounting.* In October 1998, the Company adopted SFAS 133 which established new accounting and reporting guidelines for derivative instruments and hedging activities. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but redesignation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is to be measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, or the time value of options is recognized immediately in earnings. Changes in fair value for contracts which do not meet the SFAS 133 cash flow hedge definition are also recognized in earnings. Substantially all of our fixed-price contracts and interest rate swaps are designated as cash flow hedges. Pursuant to the provisions of SFAS 133, all hedging designations and the methodology for determining hedge ineffectiveness must be documented at the inception of the hedge, and, upon the initial adoption of the standard, hedging relationships must be designated anew. Based on the interpretations of these guidelines by the Staff of the Securities and Exchange Commission in September 1999, the changes in fair value of all of our derivatives during the period from October 1, 1998 to January 13, 1999 were required to be reported in results of operations, rather than in other comprehensive income.

All of the fixed-price contracts have been executed in connection with our natural gas and crude oil hedging program. For these contracts the differential between the fixed price and the floating price for each contract settlement period multiplied by the associated contract volumes is the contract profit or loss. The realized contract profit or loss is included in oil and gas sales in the period for which the underlying production was hedged. For fixed-price contracts qualifying as cash flow hedges pursuant to SFAS 133, changes in fair value for volumes not yet settled are shown as adjustments to other comprehensive income. The fair value of all fixed-price contracts are recorded as assets or liabilities in the balance sheet.

If a fixed-price contract which qualified for cash flow hedge accounting is liquidated or sold prior to maturity, the gain or loss at the time of termination remains in accumulated other comprehensive income to be amortized into oil and gas sales over the original term of the contract. Included in accumulated other comprehensive income at December 31, 2000 and 1999, were pretax unamortized deferred gains of $86.4 million and $99.7 million, respectively, related to terminated contracts. These deferred gains were recorded net of deferred tax effect. Prepayments received under fixed-price contracts with continuing performance obligations are recorded as deferred revenue and amortized into oil and gas sales over the term of the underlying contract.

For the years ended December 31, 2000, 1999 and 1998, oil and gas sales included $62.3 million of net losses, $1.5 million of net gains and $23.1 million of net gains, respectively, associated with realized gains and losses under fixed-price contracts.

Change in derivative fair value for the years ended December 31, 2000, 1999 and 1998 was comprised of the following:

| | **Years Ended December 31,** | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| | | *(in thousands)* | |
| CHANGE IN DERIVATIVE FAIR VALUE | | | |
| Change in fair value for derivatives not qualifying for hedge accounting | $ (2,632) | $ 9,740 | $ 17,346 |
| Amortization of derivative fair value gains and losses recognized in earnings prior to actual cash settlement | (6,501) | (2,943) | -- |
| Ineffective portion of derivatives qualifying for hedge accounting, including the time value component of collars | (6,429) | (7,239) | -- |
| | $ (15,562) | $ (442) | $ 17,346 |

Amounts recorded in change in derivative fair value do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption over the respective contract terms. Despite certain fixed-price contracts failing the effectiveness guidelines of SFAS 133 from time to time, fixed-price contracts continue to be effective in achieving the risk management objectives for which they were intended.

In addition to the future net settlements identified in the table under "-- Description of Contracts", we expect the following adjustments in 2001: (1) oil and gas sales will include $13.9 million of gains from the amortization of deferred gains from price-risk management activities, (2) interest expense will include $.4 million of loss from the amortization of deferred interest rate hedging losses, and (3) change in derivative fair value in the statement of operations will include a loss of $4.7 million relating to the unwinding of previously recognized net gains in this caption as actual contract cash settlements are realized and the time value component of options reverse.

*Credit Risk.* Fixed-price contract terms generally provide for monthly settlements and energy swaps provide for a net settlement due to or from the respective party, as discussed previously. The counterparties to the contracts are pipeline marketing affiliates, financial institutions, an independent power producer, a municipality and other end users. In some cases, we require letters of credit or corporate guarantees to secure the performance obligations of the contract counterparty. Should a counterparty to a contract default on a contract, there can be no assurance that we would be able to enter into a new contract with a third party on terms comparable to the original contract. We have not experienced non-performance by any counterparty.

Cancellation or termination of a fixed-price contract would subject a greater portion of our gas production to market prices, which, in a low price environment, could have an adverse effect on our future operating results. In addition, the associated carrying value of the contract would be removed from the balance sheet.

In October 1999 and June 1998, we agreed to the termination of two long-term fixed-price natural gas delivery contracts. These terminations resulted in the receipt of cash in the amount of $44.2 million and $40.1 million, respectively. The associated realized gains have been recorded in accumulated other comprehensive income, net of tax.

*Market Risk.* The differential between the floating price paid under each energy swap contract, or the cost of gas to supply physical delivery contracts, and the price received at the wellhead for our production is termed "basis" and is the result of differences in location, quality, contract terms, timing and other variables. The effective price realizations which result from the fixed-price contracts are affected by movements in basis. For the years ended December 31, 2000, 1999 and 1998, we received on an Mcf basis approximately 2%, 6% and 6% less than the prices specified in natural gas fixed-price contracts, respectively, due to basis. For oil production hedged by crude oil fixed-price contracts, we realized approximately 6%, 7% and 10% less than the specified contract prices for such years, respectively. Basis movements can result from a number of variables, including regional supply and demand factors, changes in our portfolio of fixed-price contracts and the composition of our producing property base. Basis movements are generally considerably less than the price movements affecting the underlying commodity, but their effect can be significant. A 1% move in price realization for hedged natural gas in 2001 represents a $3.5 million change in gas sales. We actively manage exposure to basis movements and from time to time will enter into contracts designed to reduce such exposure.

Changes in future gains and losses to be realized in oil and gas sales upon cash settlements of fixed-price contracts as a result of changes in market prices for oil and natural gas are expected to be offset by changes in the price received for our hedged oil and natural gas production. Because the majority of our future estimated oil and gas production is unhedged, declining oil and gas prices could have a material adverse effect on future results of operations and operating cash flows. Conversely, increases in market prices of oil and gas would benefit future results of operations and operating cash flows.

*Margin.* We are required to post margin in the form of bank letters of credit or treasury bills under certain of our fixed-price contracts. In some cases, the amount of such margin is fixed; in others, the amount changes as the market value of the respective contract changes, or if certain financial tests are not met. For the years ended December 31, 2000, 1999 and 1998, the maximum aggregate amount of margin posted was $70.8 million, $23.5 million and $23.7 million, respectively. If natural gas prices rise as they did in 2000, or if we fail to meet the financial tests contained in certain of fixed-price contracts, margin requirements increase significantly. We believe that margin requirements will be adequately met through bank credit facility availability, other existing lines of credit, or credit lines that may be obtained in the future. If we are unable to meet margin requirements, a contract could be terminated and we could be required to pay damages to the counterparty which generally approximate the cost to the counterparty of replacing the contract. At December 31, 2000, margin had been issued in the form of letters of credit totaling $70.8 million. Subsequent to December 31, 2000, margin requirements under fixed-price contracts to two counterparties were reduced, resulting in a $44 million reduction in posted margin.

**Interest Rate Sensitivity**

We have interest rate swaps designed to hedge the interest rate exposure associated with borrowings under the credit facility. As of December 31, 2000, we had fixed the interest rate on average notional amounts of $125 million and $94 million for the years ended December 31, 2001 and 2002, respectively. Under the interest rate swaps, we receive the LIBOR three-month rate (6.4% at December 31, 2000) and pay an average rate of 5.0% for each period covered by the swaps. The notional amounts are less than the maximum amount anticipated to be available under the bank credit facility for the respective years.

For each interest rate swap, the differential between the fixed rate and the floating rate multiplied by the notional amount is the swap gain or loss. This gain or loss is included in interest expense in the period for which the interest rate exposure was hedged. Pursuant to SFAS 133, if an interest rate swap qualifying as a cash flow hedge is liquidated or sold prior to maturity, the gain or loss on the interest rate swap at the time of termination remains in accumulated other comprehensive income, to be recognized as an adjustment to interest expense over the original contract term. For the year ended December 31, 2000, interest rate swaps decreased interest expense by $1.9 million. The impact of interest rate swap settlements in 1999 and 1998 was not material.

The following table provides information about our interest rate swaps and certain other financial instruments as of December 31, 2000.

| | Years Ending December 31, | | | | | Balance through | |
|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2007 | Total |
| | | | *(dollars in thousands)* | | | | |
| **Expected Maturities of Long-Term Debt:** | | | | | | | |
| Bank debt | $ -- | $ 313,800 | $ -- | $ -- | $ -- | $ -- | $ 313,800 |
| Average interest rate (1) | 6.2% | 5.3% | -- | -- | -- | -- | 5.8% |
| Senior Notes | $ -- | $ -- | $ -- | $ -- | $ -- | $ 200,000 | $ 200,000 |
| Fixed interest rate | 6.9% | 6.9% | 6.9% | 6.9% | 6.9% | 6.9% | 6.9% |
| Subordinated Notes | $ -- | $ -- | $ -- | $ 93,700 | $ -- | $ -- | $ 93,700 |
| Fixed interest rate | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | -- | 9.3% |
| **Interest Rate Swaps:** | | | | | | | |
| Average notional amount by year | $ 125,000 | $ 94,000 | $ -- | $ -- | $ -- | $ -- | $ 219,000 |
| Average pay rate - fixed | 5.0% | 5.0% | -- | -- | -- | -- | 5.0% |
| Average receive rate - variable (2) | 6.0% | 5.1% | -- | -- | -- | -- | 5.5% |

(1) - Based on market quotations for interest rates as of December 31, 2000 plus the appropriate credit spread for the indicated debt instrument. Does not include commitment fees. See "Item 7 -- Management's Discussion and Analysis of Financial Condition and Results of Operations -- Capital Resources and Liquidity."

(2) - Based on market quotations for interest rates as of December 31, 2000.

The estimated fair value of the Company's interest rate swaps and certain other financial instruments and the associated carrying value as of December 31, 2000 and 1999 are provided below.

| | December 31, 2000 | | December 31, 1999 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| | *(in thousands)* | | | |
| Bank debt | $ (313,800) | $ (316,568) | $ (255,600) | $ (260,494) |
| 6f% Senior Notes due 2007 | (199,156) | (193,646) | (199,034) | (177,012) |
| 9¼% Senior Subordinated Notes due 2004 | (93,953) | (96,061) | (100,588) | (99,591) |
| Interest rate swaps | 1,756 | 1,756 | 5,660 | 5,660 |
| Total | $ (605,153) | $ (604,519) | $ (549,562) | $ (531,437) |

The fair value of bank debt at December 31, 2000 and 1999 was determined by utilizing an estimated market credit spread for bank debt with comparable terms and credit quality. The fair values of the 6f% Senior Notes due 2007 and the 9¼% Senior Subordinated Notes due 2004 were determined based on market quotations for these securities. The fair value of the interest rate swaps was based on market interest rates as of each respective date.

We expect that changes in realized interest rate swap gains and losses attributable to future changes in market interest rates will be offset by changes in the interest payments hedged by these interest rate swaps. The fair value of these swaps until settlement will be subject to change as market interest rates change. Increases in market interest rates would have an adverse effect on results of operations since the majority of our bank debt interest rate exposure is unhedged.

## ITEM 8 -- FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements and supplementary data are presented on pages F-1 through F-26 inclusive, found at the end of this report.

## ITEM 9 -- CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

# PART III

## ITEM 10 -- DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required under Item 10 will be contained in our definitive proxy statement for the 2001 Annual Meeting of Shareholders and is incorporated herein by reference. The proxy statement will be filed pursuant to Regulation 14A with the Securities and Exchange Commission not later than 120 days after December 31, 2000.

## ITEM 11 -- EXECUTIVE COMPENSATION

The information required under Item 11 will be contained in the proxy statement for the 2001 Annual Meeting of Shareholders and is incorporated herein by reference.

## ITEM 12 -- SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required under Item 12 will be contained in the proxy statement for the 2001 Annual Meeting of Shareholders and is incorporated herein by reference.

## ITEM 13 -- CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required under Item 13 will be contained in the proxy statement for the 2001 Annual Meeting of Shareholders and is incorporated herein by reference.

## PART IV

### ITEM 14 -- EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. Financial Statements: See Index to Consolidated Financial Statements and Financial Statement Schedule immediately following the signature page of this report.

2. Financial Statement Schedule: See Index to Consolidated Financial Statements and Financial Statement Schedule immediately following the signature page of this report.

3. Exhibits: The following documents are filed as exhibits to this report, all of which have been previously filed or incorporated by reference except as otherwise indicated below.

| Exhibit No. | Description of Exhibit |
|---|---|
| 3.1 | Amended and Restated Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.1 of the Registrant's Registration Statement on Form S-1, Registration No. 33-69102). |
| 3.2 | Amended and Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.3 of the Registrant's Registration Statement on Form S-1, Registration No. 33-69102). |
| 4.1 | Indenture agreement dated as of June 15, 1994 for $100,000,000 of 9¼% Senior Subordinated Notes due 2004 between Louis Dreyfus Natural Gas Corp., as Issuer, and Bank of Montreal Trust Company, as Trustee (incorporated by reference to Exhibit 10.2 of the Registrant's Form 10-Q for the quarter ended September 30, 1994). |
| 4.2 | Indenture agreement dated as of December 11, 1997 for $200,000,000 of 6f% Senior Notes due 2007 between Louis Dreyfus Natural Gas Corp. and LaSalle National Bank as Trustee (incorporated by reference to Exhibit 4.1 of the Registrant's Registration Statement on Form S-4, Registration No. 333-45773). |
| *10.1 | Stock Option Plan of Louis Dreyfus Natural Gas Corp. as amended and restated effective December 1998 (incorporated by reference to Exhibit 10.1 of the Registrant's Form 10-K for the fiscal year ended December 31, 1998). |
| 10.2 | Form of Indemnification Agreement with directors of the Registrant (incorporated by reference to Exhibit 10.2 of the Registrant's Registration Statement on Form S-1, Registration No. 33-69102). |
| 10.3 | Registration Rights Agreement between the Registrant and Louis Dreyfus Natural Gas Holdings Corp. (incorporated by reference to Exhibit 10.3 of the Registrant's Registration Statement on Form S-1, Registration No. 33-76828). |
| 10.4 | Amendment dated December 22, 1993 to Registration Rights Agreement between the Registrant, Louis Dreyfus Natural Gas Holdings Corp. and S.A. Louis Dreyfus et Cie (incorporated by reference to Exhibit 10.4 of the Registrant's Registration Statement on Form S-1, Registration No. 33-76828). |
| 10.5 | Services Agreement between the Registrant and Louis Dreyfus Holding Company, Inc. (incorporated by reference to Exhibit 10.5 of the Registrant's Registration Statement Form S-1, Registration No. 33-76828). |
| 10.6 | Credit Agreement dated as of October 14, 1997, among Louis Dreyfus Natural Gas Corp., as Borrower, Bank of Montreal, as Administrative Agent, Chase Manhattan Bank, as Syndication Agent, NationsBank of Texas, N.A., as Documentation Agent, and certain other lenders signatory thereto (incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K dated October 14, 1997). |

*10.7 Amendment to Option Agreement of Simon B. Rich, Jr. (incorporated by reference to Exhibit 10.14 of the Registrant's Form 10-K for the fiscal year ended December 31, 1996).

*10.8 Form of Amendment to Outstanding Option Agreements of Employees (incorporated by reference to Exhibit 10.15 of the Registrant's Form 10-K for the fiscal year ended December 31, 1996).

*10.9 Form of Amendment to Outstanding Option Agreements of Non-Employee Directors (incorporated by reference to Exhibit 10.16 of the Registrant's Form 10-K for the fiscal year ended December 31, 1996).

*10.10 Employment Agreement, dated as of June 24, 1997, between Louis Dreyfus Natural Gas Corp. and Mark Andrews (incorporated by reference to Exhibit 10.3 to Form 8-K dated June 24, 1997, of American Exploration Company).

*10.11 Form of Change in Control Agreements between Registrant and Messrs. Mark E. Monroe, Jeffrey A. Bonney, Richard E. Bross, Ronnie K. Irani and Kevin R. White (incorporated by reference to Exhibit 10.1 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.12 Louis Dreyfus Natural Gas Corp. Deferred Stock Trust Agreement dated April 14, 1998 (incorporated by reference to Exhibit 10.2 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.13 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Mark E. Monroe (incorporated by reference to Exhibit 10.3 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.14 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Richard E. Bross (incorporated by reference to Exhibit 10.4 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.15 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Ronnie K. Irani (incorporated by reference to Exhibit 10.5 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.16 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Kevin R. White (incorporated by reference to Exhibit 10.6 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.17 Louis Dreyfus Natural Gas Corp. Non-employee Director Deferred Stock Trust Agreement dated December 1, 1998 (incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

*10.18 Amendment No. 1 to Louis Dreyfus Natural Gas Corp. Deferred Stock Trust Agreement dated September 30, 1998 (incorporated by reference to Exhibit 10.19 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

*10.19 Louis Dreyfus Natural Gas Corp. Non-Employee Director Deferred Stock Compensation Program as adopted effective July 23, 1998 (incorporated by reference to Exhibit 10.20 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

*10.20 Louis Dreyfus Natural Gas Corp. 2000 Employee Stock Purchase Plan dated May 16, 2000 (incorporated by reference to the Registrant's Registration Statement on Form S-8, Registration No. 333-37490).

21.1 List of subsidiaries of the Registrant.

23.1 Consent of Independent Auditors.

24.1 Powers of Attorney.

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* Constitutes a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report.

Certain of the exhibits to this filing contain schedules which have been omitted in accordance with applicable regulations. The Registrant undertakes to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

(b) Reports on Form 8-K.

None.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

LOUIS DREYFUS NATURAL GAS CORP.

Date: February 27, 2001 By: /s/ JEFFREY A. BONNEY
Jeffrey A. Bonney
Executive Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

| Signatures | Title | Date |
|---|---|---|
| MARK E. MONROE*<br>Mark E. Monroe | President, Chief Executive Officer and Director (principal executive officer) | February 27, 2001 |
| RICHARD E. BROSS*<br>Richard E. Bross | Executive Vice President and Director | February 27, 2001 |
| /s/ JEFFREY A. BONNEY<br>Jeffrey A. Bonney | Executive Vice President and Chief Financial Officer (principal financial and accounting officer) | February 27, 2001 |
| SIMON B. RICH, JR.*<br>Simon B. Rich, Jr. | Chairman of the Board of Directors | February 27, 2001 |
| MARK ANDREWS*<br>Mark Andrews | Vice Chairman of the Board of Directors | February 27, 2001 |
| GERARD LOUIS-DREYFUS*<br>Gerard Louis-Dreyfus | Director | February 27, 2001 |
| E. WILLIAM BARNETT*<br>E. William Barnett | Director | February 27, 2001 |
| DANIEL R. FINN, JR.*<br>Daniel R. Finn, Jr. | Director | February 27, 2001 |
| PETER G. GERRY*<br>Peter G. Gerry | Director | February 27, 2001 |
| JOHN H. MOORE*<br>John H. Moore | Director | February 27, 2001 |
| JAMES R. PAUL*<br>James R. Paul | Director | February 27, 2001 |
| NANCY K. QUINN*<br>Nancy K. Quinn | Director | February 27, 2001 |
| ERNEST F. STEINER*<br>Ernest F. Steiner | Director | February 27, 2001 |

*By: /s/ JEFFREY A. BONNEY February 27, 2001
Jeffrey A. Bonney
*Attorney-in-fact*

## LOUIS DREYFUS NATURAL GAS CORP.
### Index to Consolidated Financial Statements and Financial Statement Schedule

**CONSOLIDATED FINANCIAL STATEMENTS** **Page**



**CONSOLIDATED FINANCIAL STATEMENT SCHEDULE**



All other schedules for which provision is made in the applicable accounting regulations of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and therefore have been omitted.

**Report of Independent Auditors**

The Board of Directors and Stockholders
Louis Dreyfus Natural Gas Corp.

We have audited the accompanying consolidated balance sheets of Louis Dreyfus Natural Gas Corp. (the "Company") as of December 31, 2000 and 1999, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. Our audits also included the financial statement schedule listed in the Index to Item 14(a). These financial statements and the schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2000 and 1999, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As discussed in Note 1 of the Notes to Consolidated Financial Statements, effective October 1, 1998, the Company adopted Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities.”

ERNST & YOUNG LLP

Oklahoma City, Oklahoma
February 5, 2001

**LOUIS DREYFUS NATURAL GAS CORP.**
**Consolidated Balance Sheets**
*(dollars in thousands)*

A S S E T S

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| CURRENT ASSETS | | |
| Cash and cash equivalents | **$ 2,799** | $ 9,660 |
| Receivables: | | |
| Oil and gas sales | **109,488** | 43,782 |
| Joint interest and other, net | **9,098** | 8,923 |
| Income taxes | **9,276** | -- |
| Fixed-price contracts and other derivatives | **1,004** | 7,204 |
| Prepaids and other | **4,623** | 4,928 |
| Total current assets | **136,288** | 74,497 |
| PROPERTY AND EQUIPMENT, at cost, based on successful efforts accounting | **1,951,520** | 1,636,854 |
| Less accumulated depreciation, depletion and amortization | **(591,305)** | (513,715) |
| | **1,360,215** | 1,123,139 |
| OTHER ASSETS | | |
| Fixed-price contracts and other derivatives | **752** | 24,493 |
| Other, net | **4,710** | 4,958 |
| | **5,462** | 29,451 |
| | **$ 1,501,965** | $ 1,227,087 |

L I A B I L I T I E S   A N D   S T O C K H O L D E R S' E Q U I T Y

| | 2000 | 1999 |
|---|---|---|
| CURRENT LIABILITIES | | |
| Accounts payable | **$ 46,065** | $ 41,216 |
| Accrued liabilities | **14,984** | 12,413 |
| Revenues payable | **19,794** | 14,413 |
| Fixed-price contracts and other derivatives | **126,255** | 4,673 |
| Total current liabilities | **207,098** | 72,715 |
| LONG-TERM DEBT | **606,909** | 555,222 |
| DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES | | |
| Deferred revenue | **11,277** | 13,524 |
| Fixed-price contracts and other derivatives | **103,447** | 12,008 |
| Deferred income taxes | **19,222** | 52,341 |
| Other | **21,193** | 22,495 |
| | **155,139** | 100,368 |
| COMMITMENTS AND CONTINGENCIES (Notes 7 and 12) | | |
| STOCKHOLDERS' EQUITY | | |
| Preferred stock, par value $.01; 10 million shares authorized; no shares outstanding | **--** | -- |
| Common stock, par value $.01; 100 million shares authorized; issued and outstanding, 43,689,774 and 40,230,880 shares, respectively | **437** | 402 |
| Paid-in capital | **504,989** | 420,859 |
| Retained earnings | **126,409** | 28,149 |
| Accumulated other comprehensive income (loss) | **(99,005)** | 49,981 |
| Treasury stock, at cost, 589 and 32,139 common shares, respectively | **(11)** | (609) |
| | **532,819** | 498,782 |
| | **$ 1,501,965** | $ 1,227,087 |

*See accompanying notes to consolidated financial statements.*

**LOUIS DREYFUS NATURAL GAS CORP.**
**Consolidated Statements of Operations**
*(in thousands, except per share data)*

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| REVENUES | | | |
| Oil and gas sales | **$ 489,703** | $ 290,878 | $ 271,575 |
| Change in derivative fair value | **(15,562)** | (442) | 17,346 |
| Other income | **3,144** | 12,170 | 4,462 |
| | **477,285** | 302,606 | 293,383 |
| EXPENSES | | | |
| Operating costs | **86,915** | 66,039 | 66,295 |
| General and administrative | **24,144** | 23,995 | 25,971 |
| Exploration costs | **25,654** | 14,258 | 34,543 |
| Depreciation, depletion and amortization | **129,323** | 117,080 | 131,408 |
| Impairment | **10,439** | 4,877 | 52,522 |
| Interest | **41,431** | 40,667 | 40,849 |
| | **317,906** | 266,916 | 351,588 |
| Income (loss) before income taxes and cumulative effect of accounting change | **159,379** | 35,690 | (58,205) |
| Income tax provision (benefit) | **61,119** | 14,276 | (13,924) |
| Net income (loss) before cumulative effect of accounting change | **98,260** | 21,414 | (44,281) |
| Cumulative effect of accounting change, net of tax | **--** | -- | 964 |
| NET INCOME (LOSS) | **$ 98,260** | $ 21,414 | $ (43,317) |
| | | | |
| PER SHARE | | | |
| Basic: | | | |
| Net income (loss) before cumulative effect of accounting change | **$ 2.35** | $ .53 | $ (1.10) |
| Cumulative effect of accounting change | **--** | -- | .02 |
| Net income (loss) - basic | **$ 2.35** | $ .53 | $ (1.08) |
| Diluted: | | | |
| Net income (loss) before cumulative effect of accounting change | **$ 2.29** | $ .53 | $ (1.10) |
| Cumulative effect of accounting change | -- | -- | .02 |
| Net income (loss) - diluted | **$ 2.29** | $ .53 | $ (1.08) |
| | | | |
| Weighted average number of common shares: | | | |
| Basic | **41,830** | 40,153 | 40,107 |
| Diluted | **42,836** | 40,389 | 40,107 |

*See accompanying notes to consolidated financial statements.*

## LOUIS DREYFUS NATURAL GAS CORP.
## Consolidated Statements of Stockholders' Equity
*(in thousands)*

| | Common Stock | Additional Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | Treasury Stock | Total Stockholders' Equity |
|---|---|---|---|---|---|---|
| BALANCE AT DECEMBER 31, 1997 | $ 401 | $ 418,751 | $ 50,052 | $ -- | $ -- | $ 469,204 |
| Comprehensive income: | | | | | | |
| Net loss | -- | -- | (43,317) | -- | -- | (43,317) |
| Other comprehensive income, net of tax: | | | | | | |
| Cumulative effect of accounting change | -- | -- | -- | 97,681 | -- | 97,681 |
| Reclassification adjustments - contract settlements | -- | -- | -- | (4,431) | -- | (4,431) |
| Total comprehensive income | -- | -- | -- | -- | -- | 49,933 |
| Exercise of stock options | -- | 324 | -- | -- | -- | 324 |
| BALANCE AT DECEMBER 31, 1998 | 401 | 419,075 | 6,735 | 93,250 | -- | 519,461 |
| Comprehensive income: | | | | | | |
| Net income | -- | -- | 21,414 | -- | -- | 21,414 |
| Other comprehensive loss, net of tax: | | | | | | |
| Change in fixed-price contract and other derivative fair value | -- | -- | -- | (38,881) | -- | (38,881) |
| Reclassification adjustments - contract settlements | -- | -- | -- | (4,388) | -- | (4,388) |
| Total comprehensive loss | -- | -- | -- | -- | -- | (21,855) |
| Exercise of stock options | 1 | 1,784 | -- | -- | -- | 1,785 |
| Treasury shares purchased | -- | -- | -- | -- | (609) | (609) |
| BALANCE AT DECEMBER 31, 1999 | 402 | 420,859 | 28,149 | 49,981 | (609) | 498,782 |
| Comprehensive income: | | | | | | |
| Net income | -- | -- | 98,260 | -- | -- | 98,260 |
| Other comprehensive loss, net of tax: | | | | | | |
| Change in fixed-price contract and other derivative fair value | -- | -- | -- | (183,271) | -- | (183,271) |
| Reclassification adjustments - contract settlements | -- | -- | -- | 34,285 | -- | 34,285 |
| Total comprehensive loss | -- | -- | -- | -- | -- | (50,726) |
| Sale of common stock | 24 | 70,980 | -- | -- | -- | 71,004 |
| Exercise of stock options and warrants | 11 | 12,945 | -- | -- | -- | 12,956 |
| Treasury shares awarded to directors and employees | – | 205 | – | – | 598 | 803 |
| BALANCE AT DECEMBER 31, 2000 | $ 437 | $ 504,989 | $ 126,409 | $ (99,005) | $ (11) | $ 532,819 |

*See accompanying notes to consolidated financial statements.*

**LOUIS DREYFUS NATURAL GAS CORP.**
**Consolidated Statements of Cash Flows**
*(in thousands)*

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income (loss) | **$ 98,260** | $ 21,414 | $ (43,317) |
| Items not affecting cash flows: | | | |
| Depreciation, depletion and amortization | **129,323** | 117,080 | 131,408 |
| Impairment | **10,439** | 4,877 | 52,522 |
| Deferred income taxes | **58,195** | 13,745 | (14,524) |
| Exploration costs | **25,654** | 14,258 | 34,543 |
| Change in derivative fair value | **15,562** | 442 | (17,346) |
| Gain on sale of property | **(1,003)** | (398) | (166) |
| Other | **1,012** | 413 | 1,799 |
| Net change in operating assets and liabilities: | | | |
| Accounts receivable | **(72,735)** | 2,897 | 27,529 |
| Prepaids and other | **305** | (356) | 8,093 |
| Accounts payable | **4,849** | 2,994 | (23,179) |
| Accrued liabilities | **2,711** | 717 | (6,646) |
| Revenues payable | **5,381** | 3,473 | (3,278) |
| | **277,953** | 181,556 | 147,438 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Exploration and development expenditures | **(238,845)** | (143,521) | (222,400) |
| Acquisition of proved oil and gas properties | **(167,432)** | (34,784) | (4,500) |
| Additions to other property and equipment | **(5,122)** | (1,560) | (2,615) |
| Proceeds from sale of property and equipment | **11,399** | 12,659 | 14,413 |
| Change in other assets | **419** | (456) | (172) |
| | **(399,581)** | (167,662) | (215,274) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Proceeds from bank borrowings | **573,250** | 368,169 | 475,362 |
| Repayments of bank borrowings | **(515,050)** | (409,769) | (443,662) |
| Repayments of subordinated notes | **(6,549)** | -- | -- |
| Sale of common stock | **71,004** | -- | -- |
| Proceeds from contract termination | **--** | 44,153 | 40,136 |
| Proceeds from stock options and warrants exercised | **11,280** | 1,710 | 324 |
| Sale (purchase) of treasury shares | **49** | (609) | -- |
| Change in deferred revenue | **(2,247)** | (2,027) | (1,836) |
| Change in gains from price-risk management activities | **(13,260)** | (5,762) | (2,321) |
| Change in other long-term liabilities | **(3,710)** | (2,638) | (3,166) |
| | **114,767** | (6,773) | 64,837 |
| Change in cash and cash equivalents | **(6,861)** | 7,121 | (2,999) |
| Cash and cash equivalents, beginning of year | **9,660** | 2,539 | 5,538 |
| Cash and cash equivalents, end of year | **$ 2,799** | $ 9,660 | $ 2,539 |
| SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION | | | |
| Interest paid, net of capitalized interest | **$ 39,460** | $ 39,722 | $ 38,326 |
| Income taxes paid | **10,572** | 858 | 335 |

*See accompanying notes to consolidated financial statements.*

## LOUIS DREYFUS NATURAL GAS CORP.
## Notes to Consolidated Financial Statements

### Note 1 -- SIGNIFICANT ACCOUNTING POLICIES

**General.** Louis Dreyfus Natural Gas Corp. is one of the largest independent natural gas companies in the United States engaged in the acquisition, development, exploration, production and marketing of natural gas and crude oil. At December 31, 2000, approximately 44% of our common stock was owned by various subsidiaries of Societe Anonyme Louis Dreyfus & Cie (collectively S.A. Louis Dreyfus et Cie). See Note 6 -- Transactions with Related Parties. Our accounting policies reflect industry practices and conform to accounting principles generally accepted in the United States. The more significant of these policies are briefly described below.

**Principles of Consolidation and Basis of Presentation.** The accompanying consolidated financial statements include the accounts of Louis Dreyfus Natural Gas Corp. and our wholly-owned subsidiaries after elimination of all material intercompany accounts and transactions.

**Use of Estimates.** The preparation of the financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

**Cash and Cash Equivalents.** Cash and cash equivalents consist of all demand deposits and funds invested in short-term investments with original maturities of three months or less.

**Concentration of Credit Risk.** We sell oil and natural gas to various customers, participate with other parties in the drilling, completion and operation of oil and natural gas wells, and enter into energy swaps and physical delivery contracts, some of which are long-term. The majority of our accounts receivable are due from purchasers of oil and natural gas and from fixed-price contract counterparties. Certain of these receivables are subject to collateral or margin requirements. We have established procedures to monitor credit risk and have not experienced significant credit losses in prior years. See Note 12 -- Derivatives -- Credit Risk. At December 31, 2000 and 1999, joint interest and other receivables are shown net of allowance for doubtful accounts of $.9 million and $1.1 million, respectively.

**Property and Equipment.** We utilize the successful efforts method of accounting for oil and natural gas producing activities. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, these costs are charged to expense. Other exploration costs, including delay rentals and seismic costs, are charged to expense as incurred. Development costs, which include the costs of drilling and equipping development wells, whether successful or unsuccessful, are capitalized as incurred. All general and administrative costs are expensed as incurred. Depreciation, depletion and amortization of capitalized costs of proved oil and gas properties is computed by the unit-of-production method on a field-by-field basis. The costs of unproved oil and gas properties are assessed quarterly on a property-by-property basis. If unproved properties are determined to be productive, the related costs are transferred to proved oil and gas properties. If unproved properties are determined not to be productive, or if the value has been otherwise impaired, the excess carrying value is charged to expense.

Expenditures made in connection with our drilling program are presented in the accompanying statements of cash flows as investing activities. As indicated above, certain of these amounts are expensed as incurred or if unsuccessful in discovering new reserves. Investing activities for the years ended December 31, 2000, 1999 and 1998, include $17.8 million, $6.6 million and $30.5 million, respectively, of costs which have been expensed as exploration costs in the statement of operations for the corresponding periods.

The carrying value of our oil and gas properties are reviewed on a field-by-field basis for indications of impairment whenever events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether an impairment has occurred, we estimate the expected future net cash flows from our oil and gas properties as of the date of determination, and compare them to the respective carrying value amounts. These estimated future cash flows are based on proved reserves and forward market prices for oil and gas that existed as of the date of determination. Those oil and gas properties which have carrying amounts in excess of estimated future cash flows are deemed impaired. The carrying value of impaired properties is adjusted to an estimated fair value by discounting the estimated expected future cash flows attributable to the properties at a discount rate estimated to be representative of the market for such properties. The excess is charged to expense and may not be reinstated. For the years ended December 31, 2000 and 1999, we recognized impairment charges aggregating $10.4 million and $4.9 million, respectively, primarily as the result of downward revisions to estimated future recoverable reserves from certain single-well offshore properties identified in the preparation of the respective year-end reserve study. Overall, we experienced net upward proved reserve revisions of approximately 2 Bcfe and 12 Bcfe for 2000 and 1999, respectively. For 1998, we recognized impairment charges aggregating $52.5 million. The associated impairment reviews were conducted as the result of declining oil and gas prices during the year which adversely affected the estimated future cash flows from our oil and gas properties. Lower oil and gas prices or future downward revisions of reserve estimates could result in future impairment recognition.

We provide for the estimated cost, at current prices, of dismantling and removing oil and gas production facilities. These estimated costs are recorded at discounted values based on the estimated productive lives of the associated oil and gas property and amortized by the unit-of-production method. As of December 31, 2000 and 1999, estimated total future dismantling and restoration costs of $12.5 million and $12.1 million, respectively, were included in other long-term liabilities in the accompanying balance sheets.

Depreciation of other property and equipment is provided by using the straight-line method over estimated useful lives of three to 20 years. Included in depreciation, depletion and amortization expense for the years ended December 31, 2000, 1999 and 1998 is amortization of other assets totaling $.6 million, $1.4 million and $1.3 million, respectively.

**Debt Issuance Costs.** Debt issuance costs are amortized over the term of the associated debt instrument using the straight-line method. The unamortized balance of debt issuance costs included in other assets as of December 31, 2000 and 1999, was $2.4 million and $3.1 million, respectively.

**Oil and Gas Sales and Gas Imbalances.** Oil and gas revenues are recognized as oil and gas is produced and sold. We use the sales method of accounting for gas imbalances in those circumstances where we have underproduced or overproduced our ownership percentage in a property. Under this method, a receivable or a liability is recorded to the extent that an underproduced or overproduced position in a reservoir cannot be recouped through the production of remaining reserves. At December 31, 2000 and 1999, we had imbalance liabilities of $5.2 million and $4.0 million, respectively, and imbalance receivables of $2.3 million and $1.4 million, respectively.

**Income Taxes.** We file a consolidated United States income tax return which includes the taxable income or loss of our subsidiaries. Deferred federal and state income taxes are provided on all significant temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases.

**Hedging.** We reduce our exposure to unfavorable changes in oil and natural gas prices by utilizing fixed-price physical delivery contracts, energy swaps, collars and basis swaps (collectively fixed-price contracts). We also enter into interest rate swap contracts to reduce exposure to adverse interest rate fluctuations. In October 1998, we adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) which established new accounting and reporting guidelines for derivative instruments and hedging activities. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but redesignation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings, as is the time value component of our fixed-price collars. Substantially all of our fixed-price contracts and interest rate swaps are designated as cash flow hedges. Changes in the fair value of derivative instruments which are not designated as cash flow hedges or do not meet the effectiveness guidelines of SFAS 133 are recorded in earnings as the changes occur. Proceeds from the monetization of fixed-price contracts prior to their maturity are classified as financing activities in the accompanying statements of cash flows.

Adoption of SFAS 133 in October 1998 resulted in the reclassification of $62.2 million of deferred gains and $3.3 million of deferred losses resulting from terminated contracts to accumulated other comprehensive income, recorded net of deferred income tax effects. In addition, adoption resulted in the recognition of $1.0 million of net gains reflected as a cumulative effect of an accounting change. See Note 10 -- Capital Stock and Stockholders' Equity, Note 11 -- Financial Instruments, and Note 12 -- Derivatives. We do not hold or issue financial instruments with leveraged features. Pursuant to the provisions of SFAS 133, all hedging designations and the methodology for determining hedge ineffectiveness must be documented at the inception of the hedge, and, upon the initial adoption of the standard, hedging relationships must be designated anew. Based on the interpretation of these guidelines by the Staff of the Securities and Exchange Commission in September 1999, the changes in fair value of all of our derivatives during the period from October 1, 1998 to January 13, 1999 were required to be reported in results of operations, rather than in other comprehensive income.

Although certain of our fixed-price contracts may not qualify for special hedge accounting treatment from time to time under the specific guidelines of SFAS 133, we have continued to refer to these contracts in this document as hedges inasmuch as this was the intent when such contracts were executed, the characterization is consistent with the actual economic performance of the contracts, and we expect the contracts to continue to mitigate our commodity price risk in the future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS 133. See Note 12 -- Derivatives -- Accounting.

**Earnings per Share.** Basic earnings per share is computed by dividing net income by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if dilutive stock options and warrants were exercised, calculated using the treasury stock method. The diluted earnings per share calculation for the years ended December 31, 2000 and 1999 include an increase in potential shares attributable to dilutive stock options and warrants. Stock options and warrants were not considered in the diluted earnings per share calculations for 1998 as the effect would be antidilutive. Options to purchase 292,675 shares of common stock, with exercise prices ranging from $30.00 per share to $33.78 per share (with a weighted average price of $31.97 per share) were excluded from the diluted earnings per share calculation for 2000. See Note 8 -- Employee Benefit Plans and Note 10 -- Capital Stock and Stockholders' Equity for a description of potentially dilutive securities.

**Stock Options.** We account for employee stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations. No compensation expense is recorded with respect to stock options granted at prices equal to the market value of our common stock at the date of grant. Upon exercise, the excess of the proceeds over the par value of the shares issued is credited to additional paid-in capital. See Note 8 -- Employee Benefit Plans.

## Note 2 -- PROPERTY AND EQUIPMENT

**Capitalized Costs.** Our oil and gas acquisition, exploration and development activities are conducted primarily in Texas, Oklahoma, New Mexico and offshore in the Gulf of Mexico. The following table summarizes the capitalized costs associated with these activities:

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | *(in thousands)* | |
| Oil and gas properties: | | |
| Proved | $ 1,880,774 | $ 1,562,581 |
| Unproved | 34,934 | 39,572 |
| Accumulated depreciation, depletion and amortization | (575,215) | (497,349) |
| | 1,340,493 | 1,104,804 |
| Other property and equipment | 35,812 | 34,701 |
| Accumulated depreciation | (16,090) | (16,366) |
| | 19,722 | 18,335 |
| | $ 1,360,215 | $ 1,123,139 |

Depreciation, depletion and amortization expense of oil and gas properties per Mcfe was $.91, $.89 and $1.04 for the years ended December 31, 2000, 1999 and 1998, respectively. These amounts do not include impairment charges recorded in each year. See Note 1 -- Significant Accounting Policies. For the years ended December 31, 2000, 1999 and 1998, interest of $2.7 million, $2.0 million and $3.3 million, respectively, was capitalized in connection with our exploration and development activities. Depreciation of other property and equipment was $3.7 million, $3.5 million and $4.1 million for the years ended December 31, 2000, 1999 and 1998, respectively.

Unproved properties at December 31, 2000 consisted primarily of acreage positions acquired during the previous three years. These properties will be evaluated over their respective lease terms or as drilling results are determined. Certain of these acreage positions will be drilled in 2001 in connection with our exploration drilling program. If proved reserves are not ultimately discovered in commercial quantities as a result of this drilling activity, the carrying value of these positions will be charged to expense, classified as exploration costs in the statement of operations.

**Costs Incurred.** The following table summarizes the costs incurred in acquisition, exploration and development activities for the years ended December 31, 2000, 1999 and 1998, respectively.

| | Years Ended December 31, 2000 | 1999 | 1998 |
|---|---|---|---|
| | | *(in thousands)* | |
| Property acquisition costs: | | | |
| Proved | $ 167,714 | $ 36,881 | $ 4,088 |
| Unproved | 18,375 | 10,766 | 11,815 |
| | 186,089 | 47,647 | 15,903 |
| Exploration costs | 23,729 | 19,409 | 74,123 |
| Development costs | 196,741 | 116,597 | 136,462 |
| | $ 406,559 | $ 183,653 | $ 226,488 |

## Note 3 -- ACQUISITIONS

On June 15, 2000, we acquired substantially all of the oil and gas properties of Costilla Energy, Inc. for approximately $122 million in cash. The acquired properties were comprised of 135 Bcfe of net proved reserves included in 1,011 gross (607 net) producing wells at closing. The majority of the Costilla properties are located within our three core operating areas. The purchase price for the Costilla acquisition was initially funded through availability under our revolving bank credit facility. See Note 4 -- Long-Term Debt and Note 10 -- Capital Stock and Stockholder's Equity. The acquisition has been accounted for using the purchase method of accounting.

During 2000, 1999 and 1998, we made numerous other acquisitions of proved oil and gas properties, the net purchase price of which aggregated $45.8 million, $34.8 million and $4.1 million, respectively. The results of operations related to these acquisitions have been included in the accompanying statements of operations and cash flows for the periods subsequent to the closing of each transaction.

## Note 4 -- LONG-TERM DEBT

Long-term debt consists of the following:

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | *(in thousands)* | |
| Bank Debt: | | |
| $450 Million Revolving Credit Facility | $ 300,600 | $ 255,600 |
| Other Lines of Credit | 13,200 | -- |
| | 313,800 | 255,600 |
| 6f% Senior Notes due 2007 | 199,156 | 199,034 |
| 9¼% Senior Subordinated Notes due 2004 | 93,953 | 100,588 |
| | $ 606,909 | $ 555,222 |

**$450 Million Revolving Credit Facility.** We have a revolving credit facility with a syndicate of banks which provides up to $450 million in borrowings. Letters of credit under the credit facility are limited to $75 million of this total availability. The credit facility allows us to draw on the full $450 million credit line without restrictions tied to periodic revaluations of our oil and gas reserves provided we continue to maintain an investment grade credit rating from either Standard & Poor's Ratings Service or Moody's Investors Service. We currently have senior unsecured credit ratings of BBB and Baa3 from Standard & Poor's and Moody's, respectively. A borrowing base can be required only upon the vote by a majority in interest of the lenders after the loss of an investment grade credit rating. No principal payments are required under the credit facility prior to maturity on October 14, 2002. We have relied upon the credit facility to provide funds for acquisitions and drilling activity, and to provide letters of credit for margin requirements under fixed-price contracts. See Note 12 -- Derivatives. As of December 31, 2000, we had $300.6 million of principal and $71.6 million of letters of credit outstanding under the credit facility.

We have the option of borrowing at a LIBOR-based interest rate or the Base Rate (approximating the prime rate). The LIBOR interest rate margin and the facility fee payable under the credit facility are subject to a sliding scale based on our senior debt credit rating. At December 31, 2000, the applicable interest rate was LIBOR plus 23 basis points. The credit facility also requires the payment of a facility fee equal to 12 basis points of the total commitment. The average interest rate for borrowings under the credit facility was 6.9% at December 31, 2000. Including the effect of interest rate swaps which hedge a portion of the interest rate exposure attributable to this facility, the effective interest rate was 6.2%. See Note 12 -- Derivatives for a description of the interest rate swaps hedging a portion of the credit facility's outstanding debt.

The credit facility contains various affirmative and restrictive covenants which, among other things, limit total indebtedness to $700 million ($625 million of senior indebtedness) and require us to meet certain financial tests. Borrowings under the credit facility are unsecured.

**Other Lines of Credit.** We have certain other unsecured lines of credit available to use, which aggregated $50.1 million as of December 31, 2000. These short-term lines of credit are primarily used for working capital purposes. Borrowings under these credit lines totaled $13.2 million as of December 31, 2000. Outstanding letters of credit were immaterial. Repayment of indebtedness under these credit lines is expected to be made through the revolving bank credit facility availability.

**6f% Senior Notes due 2007.** In December 1997, we issued $200 million principal amount, $198.8 million net of discount, of 6f% Senior Notes due 2007. Interest is payable semi-annually on June 1 and December 1. The associated indenture agreement contains restrictive covenants which place limitations on the amount of liens and our ability to enter into sale and leaseback transactions.

**9¼% Senior Subordinated Notes due 2004.** In June 1994, we issued $100 million principal amount, $98.5

million net of discount, of 9¼% Senior Subordinated Notes due 2004. Interest is payable semi-annually on June 15 and December 15. The associated indenture agreement contains restrictive covenants which limit, among other things, the prepayment of the subordinated notes, the incurrence of additional indebtedness, the payment of dividends and the disposition of assets. We purchased $6.3 million principal amount of these notes in the open market during 2000, leaving an outstanding unpaid principal balance of $93.7 million as of December 31, 2000.

The amount of required principal payments for the next five years and thereafter as of December 31, 2000 are as follows: 2001 - $0; 2002 - $313.8 million; 2003 - $0; 2004 - $93.7 million; 2005 - $0; thereafter - $200 million.

**Note 5 -- INCOME TAXES**

The significant components of income tax expense (benefit) before cumulative effect of accounting change for the years ended December 31, 2000, 1999 and 1998 are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| | | *(in thousands)* | |
| Current tax expense: | | | |
| Federal | $ 2,579 | $ 497 | $ 527 |
| State | 345 | 34 | 73 |
| | 2,924 | 531 | 600 |
| Deferred tax expense (benefit): | | | |
| Federal | 51,325 | 12,054 | (12,766) |
| State | 6,870 | 1,691 | (1,758) |
| | 58,195 | 13,745 | (14,524) |
| | $ 61,119 | $ 14,276 | $ (13,924) |

The provision for income taxes before cumulative effect of accounting change differed from the computed "expected" income tax provision using statutory rates on income before income taxes for the following reasons:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| | | *(in thousands)* | |
| Computed "expected" income tax | $ 55,783 | $ 12,492 | $ (20,372) |
| Increases (reductions) in taxes resulting from: | | | |
| State income taxes, net of federal benefit | 4,690 | 1,121 | (1,095) |
| Permanent differences (principally related to basis differences in oil and gas properties) | 525 | 588 | 6,133 |
| Change in valuation allowance | -- | (194) | 2,667 |
| Section 29 credits | (15) | (394) | (851) |
| Other | 136 | 663 | (406) |
| | $ 61,119 | $ 14,276 | $ (13,924) |

As a result of employee stock options exercised during 2000, an additional $1.7 million tax benefit was realized, reflected in the accompanying balance sheet for December 31, 2000 as an increase to income taxes receivable and an increase to additional paid-in capital.

Deferred tax assets and liabilities resulting from differences between the financial statement carrying amounts and the tax bases of assets and liabilities, consist of the following:

| | December 31, 2000 | December 31, 1999 |
|---|---|---|
| | *(in thousands)* | |
| Deferred tax liabilities: | | |
| Capitalized costs and related depreciation, depletion and amortization | $ 134,383 | $ 93,414 |
| Fixed-price contracts and other derivatives | 1,595 | 12,045 |
| Other | 12,042 | 102 |
| | 148,020 | 105,561 |
| Deferred tax assets: | | |
| Deferred revenue | 4,284 | 5,139 |
| Fixed-price contracts and other derivatives | 87,287 | 6,339 |
| Alternative minimum tax credits | 6,136 | 6,136 |
| Net operating loss carryforwards | 60,855 | 85,074 |
| Other | 735 | 735 |
| | 159,297 | 103,423 |
| Valuation allowance for net operating loss carryforwards | (30,499) | (50,203) |
| | 128,798 | 53,220 |
| Net deferred tax liability | $ 19,222 | $ 52,341 |

At December 31, 2000, we had U.S. Federal net operating loss carryforwards of $174 million that expire beginning in 2001 and alternative minimum tax credit carryforwards of $6.1 million that can be carried forward indefinitely but which can be used only to reduce regular tax liabilities in excess of alternative minimum tax liabilities. Net operating loss carryforwards of $87 million may expire without utilization due to the change of control provisions of Section 382 of the Internal Revenue Code. Such expirations have been fully reserved through the valuation allowance. We are pursuing a strategy anticipated to increase the utilization of net operating loss carryforwards otherwise expected to expire by as much as $46 million. This anticipated benefit will be recognized in the tax provision when realized.

## Note 6 -- TRANSACTIONS WITH RELATED PARTIES

**Fixed-Price Contract Activity.** In 1993, we entered into a fixed-price sales contract with S.A. Louis Dreyfus et Cie hedging 33 Bcf of natural gas over a five-year period beginning in 1996, at a weighted-average fixed price of $2.49 per Mcf. For the year ended December 31, 2000, this contract resulted in a realized hedging loss of $7.4 million included in results of operations. For the years ended December 31, 1999 and 1998, the contract resulted in realized hedging gains of $3.4 million and $2.9 million, respectively.

**General and Administrative Expense.** We are a party to a services agreement under which S.A. Louis Dreyfus et Cie provides certain administrative and support services (principally insurance and related services) on our behalf. These services are billed to us at amounts approximating cost. General and administrative expenses for the years ended December 31, 2000, 1999 and 1998 include $.4 million, $.5 million and $1.4 million, respectively, for such services.

## Note 7 -- COMMITMENTS AND CONTINGENCIES

**Litigation.** Louis Dreyfus Natural Gas Corp. is one of numerous defendants in several lawsuits originally filed in 1995, subsequently consolidated with related litigation, and now pending in the Texas 93rd Judicial District Court in Hildago County, Texas. The lawsuit alleges that the plaintiffs, a group of local landowners and businesses, have suffered damages including, but not limited to, property damage and lost profits of approximately $60 million as the result of an underground hydrocarbon plume within the city of McAllen, Texas. The lawsuit alleges that gas wells and related pipeline facilities operated by us, and other facilities operated by other defendants, caused the plume. In August 1999, the plaintiffs' experts produced reports that suggested we might be considered a significant contributor to the plume. Our investigation into this matter has not found any leaks or discharges from our facilities. In addition, our investigation has revealed the plume to be unrelated to our gas wells and facilities. Trial is not anticipated to commence until the second half of 2001. We will vigorously defend our interests in this case. We do not presently expect the ultimate outcome of the case to have a material adverse impact on our financial position or results of operations; however, results of litigation are inherently unpredictable and this estimate may change in the future.

We were a defendant in various other legal proceedings as of December 31, 2000, which are routine and incidental to our business. We will vigorously defend our interests in these proceedings. While the ultimate results of these proceedings cannot be predicted with certainty, we do not believe that the outcome of these matters will have a material adverse effect on our financial position or results of operations.

**Rental Commitments.** Minimum annual rental commitments as of December 31, 2000 under noncancellable office space leases are as follows: 2001 - $2.6 million; 2002 - $2.1 million; 2003 - $2.0 million; 2004 - $1.0 million; 2005 and thereafter - $5.2 million. Approximately $800,000 of such rental commitments is included in other accrued liabilities as of December 31, 2000. Rent expense included in results of operations for the three years ended December 31, 2000, 1999 and 1998 was $1.6 million, $1.5 million and $2.1 million, respectively.

**Note 8 -- EMPLOYEE BENEFIT PLANS**

**401(k) Plan.** Our employees who have completed a specified term of service are eligible for participation in the Louis Dreyfus Natural Gas Profit Sharing and 401(k) Plan and Trust Agreement. Pursuant to the plan provisions, employee contributions can be made up to 17% of compensation. Employer contributions are discretionary. Employees vest in employer contributions at 20% per year of service. For the years ended December 31, 2000, 1999 and 1998, we contributed $1.4 million, $1.3 million and $1.2 million, respectively, to the 401(k) plan.

**Employee Stock Purchase Plan.** The Louis Dreyfus Natural Gas Corp. 2000 Employee Stock Purchase Plan provides eligible employees with the opportunity to purchase shares of our common stock through payroll deductions at a discount from the market value of the shares and on a tax-favorable basis.

**Stock Compensation Plans.** The Louis Dreyfus Natural Gas Corp. Deferred Stock Trust, established in 1998, serves as a depositary for restricted stock awards granted pursuant to the underlying agreement. Common stock contributed to the trust can be distributed to the beneficiary only upon termination of employment or other specified events. Also in 1998, we established a separate deferred stock trust for use in compensating our non-employee directors. At December 31, 2000, these trusts held a combined 107,427 shares of common stock. Compensation expense of $614,000 was recorded for the year ended December 31, 2000, relating to stock awards granted under these trust agreements.

Officers, directors and certain key employees have been granted options to purchase common stock under the 1993 Stock Option Plan, as amended. Both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code and options which are not qualified as incentive stock options may be granted under the plan. The maximum number of common shares presently issuable is three million shares, subject to appropriate equitable adjustment in the event of a reorganization, stock split, stock dividend, reclassification or other change affecting the common stock. As of December 31, 2000 and 1999, options to purchase 144,870 shares and 418,920 shares of common stock, respectively, were available for grant. Options granted under the option plan vest over a period of time based on the nature of the grants and as defined in the individual grant agreements, but generally over a four year-period. The exercise price of each option equals the market price of the common stock on the date of grant and an option's expiration date is ten years from the date of issuance.

The following pro forma information, as required by Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (SFAS 123), presents net income and earnings per share information as if the stock options issued after December 31, 1994 were accounted for using the fair value method. The fair value of stock options issued for each year was estimated at the date of grant using a Black-Scholes option pricing model.

Valuation assumptions for option grants in 2000, 1999 and 1998 included the following: risk-free interest rates of 5.9%, 5.8% and 4.9%, respectively; no dividends over the option term; stock price volatility factors of .50, .37 and .36, respectively, and a weighted average expected option life of five years. The estimated fair value as determined by the model is amortized to expense over the respective vesting period. The SFAS 123 pro forma information presented below is not necessarily indicative of the pro forma effects to be presented in future periods. Additionally, option grants made prior to 1995 have been excluded.

The SFAS 123 pro forma information is as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| | *(in thousands, except per share data)* | | |
| Net income (loss) | $ 95,443 | $ 18,988 | $ (45,194) |
| Net income (loss) per share | 2.23 | .47 | (1.13) |

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions, including expected stock price volatility. Because these stock options issued under the option plan have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in our opinion, the existing models do not necessarily provide a reliable single measure of stock option fair value.

Stock option transactions for 2000, 1999 and 1998 are summarized as follows:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | **2000** | | **1999** | | **1998** | |
| | **Shares** | **Weighted-Average Exercise Price** | **Shares** | **Weighted-Average Exercise Price** | **Shares** | **Weighted-Average Exercise Price** |
| Outstanding at beginning of year | 2,368,817 | $ 17.38 | 2,124,580 | $ 16.85 | 1,708,330 | $ 19.03 |
| Granted | 292,675 | 31.97 | 426,000 | 19.16 | 1,054,750 | 15.51 |
| Exercised | (743,115) | 17.07 | (159,513) | 15.45 | (22,500) | 15.05 |
| Canceled | (18,625) | 16.79 | (22,250) | 14.44 | (616,000) | 20.68 |
| Outstanding at end of year | 1,899,752 | 19.76 | 2,368,817 | 17.38 | 2,124,580 | 16.85 |
| Exercisable at end of year | 862,080 | 17.86 | 1,148,317 | 17.21 | 909,830 | 17.27 |
| Weighted-average fair value of options granted during year | $ 16.19 | | $ 8.05 | | $ 6.17 | |

Outstanding options to acquire 292,675 shares of stock at December 31, 2000 had exercise prices ranging from $30.00 to $33.78 per share (20,000 of which are exercisable at a weighted-average exercise price of $30.00 per share), had a weighted-average exercise price of $31.97, and had a weighted-average remaining contractual life of 9.8 years. Outstanding options to acquire 914,440 shares of stock at December 31, 2000 had exercise prices ranging from $18.00 to $23.16 per share (478,440 of which are exercisable at a weighted-average price of $20.34 per share), had a weighted-average exercise price of $20.29, and had a weighted-average remaining contractual life of 7.1 years. The balance of options outstanding at December 31, 2000 had exercise prices ranging from $12.47 to $16.69 per share (363,640 of which are exercisable at a weighted-average price of $13.93 per share), had a weighted-average exercise price of $13.90, and had a weighted-average remaining contractual life of 7.2 years.

## Note 9 -- SIGNIFICANT CUSTOMERS

Our oil and gas production is sold under contracts with various purchasers. For the year ended December 31, 2000, gas sales to Enron Corp., Duke Energy, and PG&E Corp. approximated 17%, 17% and 14% of total revenues, respectively. For the year ended December 31, 1999, gas sales to Enron Corp. and PG&E Corp. approximated 17% and 14% of total revenues, respectively. For the year ended December 31, 1998, gas sales to PG&E Corp. approximated 20% of total revenues. We believe that alternative purchasers are available, if necessary, to purchase our production at prices substantially similar to those received from these significant purchasers in 2000.

## Note 10 -- CAPITAL STOCK AND STOCKHOLDERS' EQUITY

**Common Stock**. The following table presents our common stock activity for the periods presented:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | *(in thousands)* | |
| Common Stock Activity: | | | |
| Balance, beginning of year | 40,199 | 40,110 | 40,088 |
| Sale of common stock | 2,405 | -- | -- |
| Exercise of warrants | 363 | -- | -- |
| Exercise of stock options | 690 | 121 | 22 |
| Treasury shares reissued (purchased) | 32 | (32) | -- |
| Balance, end of year | 43,689 | 40,199 | 40,110 |

In 2000, we sold 2.4 million shares of common stock at $31.00 per share ($29.53 per share net of underwriting discount) in a public offering. Proceeds from the offering of $70.9 million received in July 2000 were applied to reduce a majority of the indebtedness incurred in connection with the acquisition of properties from Costilla Energy, Inc. In addition, an indirect wholly-owned subsidiary of S.A. Louis Dreyfus et Cie sold 1.6 million shares of our common stock in the offering. Subsequent to the offering, S.A. Louis Dreyfus et Cie through its subsidiaries owned 19.2 million shares, or approximately 44% of the total issued and outstanding common shares.

**Warrants.** At December 31, 2000, warrants were outstanding to purchase 317,566 shares of common stock, all of which were exercisable. The warrants have an exercise price of $17.69 per share and expire in December 2004. During 2000, 740,987 warrants were exercised resulting in the issuance of 363,541 shares of common stock. Additional warrants to purchase 356,489 shares expired unexercised in April 1999. All warrants were originally issued in 1997 in connection with the acquisition of American Exploration Company.

**Other Comprehensive Income.** The components of other comprehensive income and related tax effects for the years ended December 31, 2000, 1999 and 1998 are shown as follows:

| | Gross | Tax Effect | Net of Tax |
|---|---|---|---|
| | | *(in thousands)* | |
| Year ended December 31, 2000: | | | |
| Change in fixed-price contract and other derivative fair value | $ (295,599) | $ (112,328) | $ (183,271) |
| Reclassification adjustments - contract settlements | 55,299 | 21,014 | 34,285 |
| | $ (240,300) | $ (91,314) | $ (148,986) |
| Year ended December 31, 1999: | | | |
| Change in fixed-price contract and other derivative fair value | $ (62,711) | $ (23,830) | $ (38,881) |
| Reclassification adjustments - contract settlements | (7,078) | (2,690) | (4,388) |
| | $ (69,789) | $ (26,520) | $ (43,269) |
| Year ended December 31, 1998: | | | |
| Cumulative effect of accounting change | $ 157,550 | $ 59,869 | $ 97,681 |
| Reclassification adjustments - contract settlements | (7,147) | (2,716) | (4,431) |
| | $ 150,403 | $ 57,153 | $ 93,250 |

## Note 11 -- FINANCIAL INSTRUMENTS

The following information is provided regarding the estimated fair value of the financial instruments, including derivative assets and liabilities as defined by SFAS 133 that we held as of December 31, 2000 and 1999, and the methods and assumptions used to estimate their fair value:

| | December 31, 2000 | | December 31, 1999 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | | *(in thousands)* | | |
| Derivative assets: | | | | |
| Fixed-price natural gas swaps | $ -- | $ -- | $ 16,433 | $ 16,433 |
| Fixed-price natural gas collars | -- | -- | 1,323 | 1,323 |
| Fixed-price natural gas delivery contracts | -- | -- | 7,921 | 7,921 |
| Fixed-price crude oil swaps | -- | -- | 360 | 360 |
| Interest rate swaps | 1,756 | 1,756 | 5,660 | 5,660 |
| Derivative liabilities: | | | | |
| Fixed-price natural gas swaps | (55,923) | (55,923) | (4,329) | (4,329) |
| Fixed-price natural gas collars | (26,054) | (26,054) | -- | -- |
| Fixed-price natural gas delivery contracts | (146,234) | (146,234) | (9,081) | (9,081) |
| Natural gas basis swaps | (1,491) | (1,491) | (3,271) | (3,271) |
| Bank debt (1) | (313,800) | (316,568) | (255,600) | (260,494) |
| 6f% Senior Notes due 2007 (1) | (199,156) | (193,646) | (199,034) | (177,012) |
| 9¼% Senior Subordinated Notes due 2004 (1) | (93,953) | (96,061) | (100,588) | (99,591) |

(1) - Carrying amounts do not include capitalized debt issuance costs. See Note 1 -- Significant Accounting Policies -- Debt Issuance Costs.

Cash and cash equivalents, receivables, accounts payable, accrued liabilities and revenues payable were each estimated to have a fair value approximating the carrying amount due to the short maturity of those instruments or to the criteria used to determine carrying value in the financial statements.

The fair value of fixed-price contracts as of December 31, 2000 and 1999 was estimated based on market prices of natural gas and crude oil for the periods covered by the contracts. The net differential between the prices in each contract and market prices for future periods, as adjusted for estimated basis, has been applied to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on a contract-by-contract basis at rates commensurate with our estimation of contract performance risk and counterparty credit risk. The fair value of derivative instruments which contain options (such as collar structures) has been estimated based on remaining term, volatility and other factors. The terms and conditions of our fixed-price delivery contracts and certain financial swaps are uniquely tailored to our circumstances. In addition, certain of the contracts hedge gas production for periods beyond five years into the future. The market for natural gas beyond the five-year horizon is illiquid and published market quotations are not available. We have relied upon near-term market quotations, longer-term over-the-counter market quotations and other market information to determine fair value estimates. See Note 12 -- Derivatives -- Accounting.

The change in carrying value of fixed-price contracts and interest rate swaps in the December 31, 2000 balance sheet compared to the December 31, 1999 balance sheet resulted from a significant increase in market prices for natural gas and an increase in interest rates. Derivative liabilities reflected as current in the December 31, 2000 balance sheet represent the estimated fair value of fixed-price contract settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and gas as of the balance sheet date. The offsetting increase in value of the hedged future production has not been accrued in the accompanying balance sheet, creating the appearance of a working capital deficit from these contracts. The contract settlement amounts are not due and payable until the monthly period that the related underlying hedged transaction occurs. In some cases the recorded liability for certain contracts significantly exceeds the total settlement amounts that would be paid to a counterparty based on prices in effect at the balance sheet date due to option time value. Since we expect to hold these contracts to maturity, this time value component has no direct relationship to actual future contract settlements and consequently does not represent a liability which will be settled in cash or realized in any way.

The vast majority of all fixed-price contract fair value changes are reflected in accumulated other comprehensive income on the face of the balance sheet, shown net of deferred tax effect. At December 31, 2000, this accounting treatment resulted in a cumulative unrealized reduction in stockholders' equity of $99.0 million, giving the appearance that a loss in net enterprise value was experienced as a result of increases in market oil and gas prices. Except for the effect of basis movements, we expect that any changes in fixed-price contract fair value attributable to changes in market prices for oil and natural gas will be offset by changes in the value of our oil and natural gas reserves. Because only 13% of the future production from our natural gas reserves is hedged, higher oil and gas prices actually increase our net enterprise value, as is apparent in the standardized measure calculation. This change in reserve value, however, is not reflected in our balance sheet. See Note 12 -- Derivatives and Note 13 -- Supplemental Information - Oil and Gas Reserves.

The fair value of bank debt at December 31, 2000 and 1999 was determined by utilizing an estimated market credit spread for bank debt with comparable terms and credit quality. The fair values of the 6f% Senior Notes due 2007 and the 9¼% Senior Subordinated Notes due 2004 were determined based on market quotations for such securities. The fair value of the interest rate swaps for each of the years presented was determined by using a third-party interest rate swap valuation model or by reliance upon third-party quotations. These valuations are based on market interest rates as of the determination date.

## Note 12 -- DERIVATIVES

**Description of Contracts.** We utilize fixed-price contracts to reduce exposure to unfavorable changes in oil and gas prices which are subject to significant and often volatile fluctuation. Fixed-price contracts are comprised of long-term delivery contracts, energy swaps, collars and basis swaps. These contracts allow us to predict with greater certainty the effective oil and gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, we will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. For the years ended December 31, 2000, 1999 and 1998, fixed-price contracts hedged 44%, 55% and 50%, respectively, of our gas production and 40%, 19% and

16%, respectively, of our oil production. Fixed-price contracts as of December 31, 2000, hedge 82 Bcf of future gas production in 2001, and 120 Bcf thereafter.

For energy swap contracts, we receive a fixed price for the respective commodity and pay a floating market price, as defined in each contract (generally NYMEX futures prices or a regional spot market index), to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty. For delivery contracts, we purchase gas in the spot market at floating market prices and deliver gas to the contract counterparty at a fixed price. Natural gas collars contain a fixed floor price (put) and ceiling price (call). If the market price of natural gas exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price. If the market price of natural gas is between the call and the put strike price, then no payments are due from either party. Under the basis swaps, we receive the floating market price for NYMEX futures and pay the floating market price plus a fixed differential for a specified regional spot market index.

The following table summarizes the estimated volumes, fixed prices, fixed-price sales and future net revenues attributable to the fixed-price contracts as of December 31, 2000. We expect the prices to be realized for hedged production to vary from the prices shown in the following table due to basis, which is the differential between the floating price paid under each energy swap contract, or the cost of gas to supply delivery contracts, and the price received at the wellhead for our hedged production. Basis differentials are caused by differences in location, quality, contract terms, timing and other variables. Future net revenues for any period are determined as the differential between the fixed prices provided by fixed-price contracts and forward market prices as of December 31, 2000, as adjusted for basis. Future net revenues change with changes in market prices and basis. See "-- Market Risk."

| | Years Ending December 31, | | | | | Balance through | |
|---|---|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2004 | 2005 | 2017 | Total |
| | *(dollars in thousands, except price data)* | | | | | | |
| **Natural Gas Swaps:** | | | | | | | |
| Contract volumes (BBtu) | 32,340 | 6,697 | 5,650 | 5,650 | 5,650 | 6,483 | 62,470 |
| Weighted-average fixed price per MMBtu (1) | $ 4.90 | $ 2.65 | $ 2.92 | $ 3.12 | $ 3.32 | $ 3.41 | $ 4.02 |
| Future fixed-price sales | $ 158,579 | $ 17,766 | $ 16,492 | $ 17,608 | $ 18,740 | $ 22,082 | $ 251,267 |
| Future net revenues (2) | $ (36,849) | $ (11,542) | $ (5,028) | $ (3,276) | $ (2,089) | $ (1,901) | $ (60,685) |
| **Natural Gas Delivery Contracts:** | | | | | | | |
| Contract volumes (BBtu) | 17,814 | 17,689 | 14,819 | 6,634 | 5,314 | 38,116 | 100,386 |
| Weighted-average fixed price per MMBtu (1) | $ 2.38 | $ 2.46 | $ 2.53 | $ 2.53 | $ 2.63 | $ 3.01 | $ 2.68 |
| Future fixed-price sales | $ 42,464 | $ 43,461 | $ 37,428 | $ 16,802 | $ 13,978 | $ 114,760 | $ 268,893 |
| Future net revenues (2) | $ (71,426) | $ (32,751) | $ (18,105) | $ (7,569) | $ (5,519) | $ (31,932) | $ (167,302) |
| **Natural Gas Collars:** | | | | | | | |
| Contract volumes (BBtu): | | | | | | | |
| Floor | 31,800 | 7,300 | -- | -- | -- | -- | 39,100 |
| Ceiling | 31,800 | 7,300 | -- | -- | -- | -- | 39,100 |
| Weighted-average fixed-price per MMBtu (1): | | | | | | | |
| Floor | $ 4.57 | $ 2.84 | $ -- | $ -- | $ -- | $ -- | $ 4.25 |
| Ceiling | $ 6.28 | $ 3.94 | $ -- | $ -- | $ -- | $ -- | $ 5.84 |
| Future fixed-price sales (4) | $ 145,447 | $ 20,732 | $ -- | $ -- | $ -- | $ -- | $ 166,179 |
| Future net revenues (2) | $ (16,201) | $ (3,902) | $ -- | $ -- | $ -- | $ -- | $ (20,103) |
| **Total Natural Gas Contracts (3):** | | | | | | | |
| Contract volumes (BBtu) | 81,954 | 31,686 | 20,469 | 12,284 | 10,964 | 44,599 | 201,956 |
| Weighted-average fixed price per MMBtu (1) | $ 4.23 | $ 2.59 | $ 2.63 | $ 2.80 | $ 2.98 | $ 3.07 | $ 3.40 |
| Future fixed-price sales (4) | $ 346,490 | $ 81,959 | $ 53,920 | $ 34,410 | $ 32,718 | $ 136,842 | $ 686,339 |
| Future net revenues (2) | $(124,476) | $ (48,195) | $ (23,133) | $ (10,845) | $ (7,608) | $ (33,833) | $ (248,090) |

(1) - The prices to be realized for hedged production are expected to vary from the prices shown due to basis. See "Market Risk."
(2) - Future net revenue amounts as presented above are undiscounted and have not been adjusted for contract performance risk or counterparty credit risk. Bracketed amounts represent decreases to future natural gas sales. See Note 11 -- Financial Instruments.
(3) - Does not include basis swaps with notional volumes by year, as follows: 2001 - 9.4 TBtu; and 2002 - 5.5 TBtu.
(4) - Assumes floor prices for natural gas collar volumes.

The estimates of future net revenues from fixed-price contracts are computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date. The market for natural gas beyond a five-year horizon is illiquid and published market quotations are not available. We have relied upon near-term market quotations, longer-term over-the-counter market quotations and other market information to determine future net revenue estimates. Forward market prices for natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility. The future net revenue estimates shown above are subject to change as forward market prices change. See Note 11 -- Financial Instruments for estimated fair value information.

**Accounting.** All fixed-price contracts have been executed in connection with our natural gas and crude oil hedging program. The differential between the fixed price and the floating price for each contract settlement period multiplied by the associated contract volume is the contract profit or loss. The realized contract profit or loss is included in oil and gas sales in the period for which the underlying production was hedged. For fixed-price contracts qualifying as cash flow hedges pursuant to SFAS 133, changes in fair value for volumes not yet settled are shown as adjustments to other comprehensive income. For those contracts not qualifying as cash flow hedges, changes in fair value are recognized in earnings. The fair value of all fixed-price contracts are recorded as assets or liabilities in the balance sheet.

If a fixed-price contract which qualified for cash flow hedge accounting is liquidated or sold prior to maturity, the gain or loss at the time of termination remains in accumulated other comprehensive income to be amortized into oil and gas sales over the original term of the contract. Included in accumulated other comprehensive income at December 31, 2000 and 1999, were pretax unamortized deferred gains of $86.4 million and $99.7 million, respectively, related to terminated contracts. These deferred gains are recorded net of deferred tax effect. Prepayments received under fixed-price contracts with continuing performance obligations are recorded as deferred revenue and amortized into oil and gas sales over the term of the underlying contract. See Note 1 -- Significant Accounting Policies -- Hedging.

For the years ended December 31, 2000, 1999 and 1998, oil and gas sales included $62.3 million of net losses, $1.5 million of net gains and $23.1 million of net gains, respectively, associated with realized gains and losses under fixed-price contracts.

Change in derivative fair value for the years ended December 31, 2000, 1999 and 1998 was comprised of the following:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | *(in thousands)* | |
| CHANGE IN DERIVATIVE FAIR VALUE | | | |
| Change in fair value for derivatives not qualifying for hedge accounting | $ (2,632) | $ 9,740 | $ 17,346 |
| Amortization of derivative fair value gains and losses recognized in earnings prior to actual cash settlement | (6,501) | (2,943) | -- |
| Ineffective portion of derivatives qualifying for hedge accounting, including the time value component of collars | (6,429) | (7,239) | -- |
| | $ (15,562) | $ (442) | $ 17,346 |

Amounts recorded in change in derivative fair value do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption over the respective contract terms. Despite certain fixed-price contracts failing the effectiveness guidelines of SFAS 133 from time to time, fixed-price contracts continue to be effective in achieving the risk management objectives for which they were intended.

In addition to the future net settlements identified in the table under "-- Description of Contracts", we expect the following adjustments in 2001: (1) oil and gas sales will include $13.9 million of gains from the amortization of deferred gains from price-risk management activities, (2) interest expense will include $.4 million of loss from the amortization of deferred interest rate hedging losses, and (3) change in derivative fair value in the statement of operations will include a loss of $4.7 million relating to the unwinding of previously recognized net gains in this caption as actual contract cash settlements are realized and the time value component of options reverse.

**Credit Risk.** Fixed-price contracts terms generally provide for monthly settlements and energy swaps provide for a net settlement due to or from the respective party as discussed previously. The counterparties to the contracts are comprised of pipeline marketing affiliates, financial institutions, an independent power producer, a municipality, and other end users. In some cases, we require letters of credit or corporate guarantees to secure the performance obligations of the contract counterparty. Should a counterparty to a contract default on a contract, there can be no assurance that we would be able to enter into a new contract with a third party on terms comparable to the original contract. We have not experienced non-performance by any counterparty.

Cancellation or termination of a fixed-price contract would subject a greater portion of our gas production to market prices, which, in a low price environment, could have an adverse effect on our future operating results. In addition, the associated carrying value of the contract would be removed from the balance sheet.

In October 1999 and June 1998, we agreed to the termination of two long-term fixed-price natural gas delivery contracts. These terminations resulted in the receipt of cash in the amount of $44.2 million and $40.1 million, respectively. The associated realized gains have been recorded in accumulated other comprehensive income, net of tax.

**Market Risk.** The differential between the floating price paid under each energy swap contract, or the cost of gas to supply physical delivery contracts, and the price received at the wellhead for our production is termed "basis" and is the result of differences in location, quality, contract terms, timing and other variables. The effective price realizations which result from the fixed-price contracts are affected by movements in basis. For the years ended December 31, 2000, 1999 and 1998, we received on an Mcf basis approximately 2%, 6% and 6% less than the prices specified in natural gas fixed-price contracts, respectively, due to basis. For oil production hedged by crude oil fixed-price contracts, we realized approximately 6%, 7% and 10% less than the specified contract prices for such years, respectively. Basis movements can result from a number of variables, including regional supply and demand factors, changes in our portfolio of fixed-price contracts and the composition of our producing property base. Basis movements are generally considerably less than the price movements affecting the underlying commodity, but their effect can be significant. A 1% move in price realization for hedged natural gas in 2001 represents a $3.5 million change in gas sales. We actively manage exposure to basis movements and from time to time will enter into contracts designed to reduce such exposure.

Changes in future gains and losses to be realized in oil and gas sales upon cash settlements of fixed-price contracts as a result of changes in market prices for oil and natural gas are expected to be offset by changes in the price received for our hedged oil and natural gas production. Because the majority of our future estimated oil and gas production is unhedged, declining oil and gas prices could have a material adverse effect on future results of operations and operating cash flows.

**Margin.** We are required to post margin in the form of bank letters of credit or treasury bills under certain fixed-price contracts. In some cases, the amount of margin is fixed; in others, the amount changes as the market value of the respective contract changes, or if certain financial tests are not met. For the years ended December 31, 2000, 1999 and 1998, the maximum aggregate amount of margin posted was $70.8 million, $23.5 million and $23.7 million, respectively. If natural gas prices were to rise, or if we failed to meet the financial tests contained in certain fixed-price contracts, margin requirements could increase significantly. We believe that margin requirements will be adequately met through bank credit facility availability, other existing lines of credit, or credit lines that may be obtained in the future. If we are unable to meet margin requirements, a contract could be terminated and we could be required to pay damages to the counterparty which generally approximate the cost to the counterparty of replacing the contract. At December 31, 2000, margin had been issued in the form of letters of credit totaling $70.8 million. Subsequent to December 31, 2000, margin requirements under fixed-price contracts to two counterparties were reduced, resulting in a $44 million reduction in posted margin.

**Interest Rate Swaps.** We have interest rate swaps designed to hedge the interest rate exposure associated with borrowings under the bank credit facility. As of December 31, 2000, we had fixed the interest rate on average notional amounts of $125 million and $94 million for the years ended December 31, 2001 and 2002, respectively. Under the interest rate swaps, we receive the LIBOR three-month rate (6.4% at December 31, 2000) and pay an average rate of 5.0% for each period covered by the swaps. The notional amounts are less than the maximum amount anticipated to be available under the bank credit facility for the respective years.

For each interest rate swap, the differential between the fixed rate and the floating rate multiplied by the notional amount is the swap gain or loss. This gain or loss is included in interest expense in the period for which the interest rate exposure was hedged. Pursuant to SFAS 133, if an interest rate swap qualifying as a cash flow hedge is liquidated or sold prior to maturity, the gain or loss on the interest rate swap at the time of termination remains in accumulated other comprehensive income, to be recognized as an adjustment to interest expense over the original contract term. At December 31, 2000 and 1999, we had deferred termination losses of $2.4 million and $2.8 million, respectively, recorded net of tax in accumulated other comprehensive income. Interest rate swaps decreased interest expense during 2000 by $1.9 million. The impact of interest rate swap settlements in 1999 and 1998 was not material.

## Note 13 -- SUPPLEMENTAL INFORMATION - OIL AND GAS RESERVES (unaudited)

The following information summarizes our net proved reserves of crude oil and natural gas and the present values of proved reserves for the three years ended December 31, 2000, 1999 and 1998. Reserve estimates for these years have been prepared by our petroleum engineers and reviewed by an independent engineering firm. All studies have been prepared in accordance with regulations prescribed by the Securities and Exchange Commission. Future net revenue is estimated by such engineers using oil and gas prices in effect as of the end of each respective year with price escalations permitted only for those properties which have wellhead contracts allowing specific increases. Future operating costs estimated in each study are based on historical operating costs incurred. Reserve quantity estimates are calculated without regard to prices in the fixed-price contracts.

The reliability of any reserve estimate is a function of the quality of available information and of engineering interpretation and judgment. Such estimates are susceptible to revision in light of subsequent drilling and production history or as a result of changes in economic conditions.

**Estimated Quantities of Oil and Gas Reserves (unaudited).** The following table presents our estimated proved reserves, all of which are located in the United States, for the years ended December 31, 2000, 1999 and 1998. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

| | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | Oil (MBbls) | Gas (MMcf) | Oil (MBbls) | Gas (MMcf) | Oil (MBbls) | Gas (MMcf) |
| **Proved Reserves:** | | | | | | |
| Beginning of year | 28,372 | 1,294,029 | 24,416 | 1,193,666 | 29,109 | 1,028,752 |
| Acquisition of proved reserves | 5,796 | 169,568 | 436 | 38,352 | 166 | 6,270 |
| Extensions and discoveries | 1,767 | 264,629 | 1,328 | 199,687 | 1,943 | 246,382 |
| Revisions of previous estimates (1) | 271 | 807 | 5,736 | (22,506) | (3,165) | 19,974 |
| Sales of reserves in place | (88) | (709) | (579) | (7,191) | (207) | (6,646) |
| Production | (2,860) | (119,855) | (2,965) | (107,979) | (3,430) | (101,066) |
| End of year | 33,258 | 1,608,469 | 28,372 | 1,294,029 | 24,416 | 1,193,666 |
| **Proved Developed Reserves:** | | | | | | |
| Beginning of year | 23,943 | 1,064,739 | 20,722 | 1,026,834 | 24,321 | 899,196 |
| End of year | 27,903 | 1,313,590 | 23,943 | 1,064,739 | 20,722 | 1,026,834 |

(1) - The crude oil volume revision for 1998 was primarily the result of a significant reduction in year-end 1998 crude oil prices compared to the prior year-end. The crude oil volume revision for 1999 was primarily the result of a significant increase in year-end 1999 crude oil prices compared to the prior year-end.

**Standardized Measure of Discounted Future Net Cash Flows (unaudited).** The following table reflects the standardized measure of discounted future net cash flows relating to our interests in proved oil and gas reserves. The future net cash inflows were developed as follows:

(1) - Estimates were made of quantities of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.

(2) - The estimated cash flows from future production of proved reserves were prepared using year-end prices for each respective year, as follows: 2000 - $25.38 per Bbl, $6.07 per Mcf; 1999 - $24.36 per Bbl, $2.19 per

Mcf; and 1998 - $9.46 per Bbl, $2.07 per Mcf. These prices do not include the effect of the fixed-price contracts.

(3) - The resulting future gross revenue streams were reduced by estimated future costs to develop and to produce the proved reserves and estimated abandonment costs, based on year-end estimates.

(4) - Future income taxes were computed by applying the appropriate statutory tax rates to the future pretax net cash flows less the current tax bases of the properties involved and related carryforwards, giving effect to permanent differences and tax credits.

(5) - The resulting future net revenue streams were reduced to present value amounts by applying a 10% discount factor.

| | December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| | | *(in thousands)* | |
| Future cash inflows (1) | $ 10,612,100 | $ 3,521,914 | $ 2,695,864 |
| Future production costs | (2,310,885) | (1,169,263) | (870,420) |
| Future development costs | (281,871) | (216,211) | (148,595) |
| Future income taxes | (2,649,077) | (460,504) | (278,363) |
| | 5,370,267 | 1,675,936 | 1,398,486 |
| Discount at 10% per year | (2,830,443) | (813,818) | (678,780) |
| Standardized measure of discounted future net cash flows (1) | $ 2,539,824 | $ 862,118 | $ 719,706 |

(1) - Future cash inflows and the standardized measure of discounted future net cash flows are based on period end oil and gas wellhead prices and do not include the effect on future cash flows from our fixed-price contracts.

The standardized measure information in the preceding table was derived from estimates of our proved oil and gas reserves contained in studies prepared by our petroleum engineers and reviewed by independent engineers. The standardized measure calculation, prepared pursuant to the provisions of Statement of Financial Accounting Standards No. 69, does not purport to represent the fair market value of our oil and gas reserves. The foregoing information is presented for comparative purposes as of the respective year-end and is not intended to reflect any changes in value which may result from subsequent price fluctuations.

**Changes Relating to the Standardized Measure of Discounted Future Net Cash Flows (unaudited).** The principal changes in the standardized measure of discounted future net cash flows attributable to our oil and gas reserves for the years ended December 31, 2000, 1999 and 1998, were as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | | (in thousands) | |
| Balance, beginning of year | $ 862,118 | $ 719,706 | $ 873,500 |
| Acquisitions of proved reserves | 388,133 | 39,877 | 4,236 |
| Extensions and discoveries, net of future development costs | 694,182 | 194,059 | 183,231 |
| Revisions of previous quantity estimates | 5,645 | 9,118 | 676 |
| Oil and gas sales, net of production costs | (465,047) | (223,298) | (182,131) |
| Sales of reserves in place | (384) | (8,236) | (7,769) |
| Net changes in sales prices and production costs | 2,032,565 | 153,701 | (234,815) |
| Development costs incurred and changes in estimated future development costs | 39,365 | (14,138) | 41,121 |
| Net change in income taxes | (1,006,549) | (96,236) | 37,783 |
| Accretion of discount | 104,972 | 81,107 | 100,265 |
| Changes in timing of production and other | (115,176) | 6,458 | (96,391) |
| Balance, end of year | $ 2,539,824 | $ 862,118 | $ 719,706 |

## Note 14 -- QUARTERLY RESULTS (unaudited)

| | 2000 | | | | 1999 | | | |
|---|---|---|---|---|---|---|---|---|
| | Fourth Quarter | Third Quarter | Second Quarter | First Quarter | Fourth Quarter | Third Quarter | Second Quarter | First Quarter |
| | *(in thousands, except per share data)* | | | | | | | |
| Revenues (1) | $ 174,366 | $ 134,461 | $ 88,004 | $ 80,454 | $ 93,115 | $ 89,946 | $ 62,422 | $ 57,123 |
| Operating profit (2) | 102,965 | 58,585 | 42,343 | 37,743 | 30,022 | 27,012 | 24,438 | 12,023 |
| Net income (loss) (3) | 50,908 | 29,425 | 9,072 | 8,855 | 12,641 | 13,048 | (454) | (3,821) |
| Net income (loss) per share - diluted | 1.15 | 0.66 | 0.22 | 0.22 | 0.31 | 0.32 | (0.01) | (0.10) |

(1) - The revenue decrease in the first quarter of 2000 is primarily attributable to change in derivative fair value. The revenue increases in the third and fourth quarters of 2000 were favorably impacted by higher oil and gas prices.
(2) - The increases in operating profits for the third and fourth quarters of 2000 are attributable to higher oil and gas prices.
(3) - Net losses in the first and second quarters of 1999 resulted from lower oil and gas prices and higher gas production. Net income in the third and fourth quarters of 2000 resulted primarily from higher oil and gas prices.

**LOUIS DREYFUS NATURAL GAS CORP.**
**Schedule II - Consolidated Valuation and Qualifying Accounts**
*(in thousands)*

| Description: | Balance at Beginning of Period | Additions (1) | Deductions (2) | Other (3) | Balance at End of Period |
|---|---|---|---|---|---|
| December 31, 2000: | | | | | |
| Allowance for doubtful accounts - Joint interest and other receivables . . . . . . . . . | $ 1,114 | $ -- | $ 57 | $ 168 | $ 889 |
| December 31, 1999: | | | | | |
| Allowance for doubtful accounts - Joint interest and other receivables . . . . . . . . . | $ 1,198 | $ 12 | $ 96 | $ – | $ 1,114 |
| December 31, 1998: | | | | | |
| Allowance for doubtful accounts - Joint interest and other receivables . . . . . . . . . | $ 1,135 | $ 176 | $ 113 | $ – | $ 1,198 |

(1) - Additions relate to provisions for doubtful accounts.
(2) - Deductions relate to the write-off of accounts receivable deemed uncollectible.
(3) - Reclassification adjustment.

## INDEX TO EXHIBITS

| Exhibit No. | Description of Exhibit |
|---|---|
| 3.1 | Amended and Restated Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.1 of the Registrant's Registration Statement on Form S-1, Registration No. 33-69102). |
| 3.2 | Amended and Restated Bylaws of the Registrant (incorporated by reference to Exhibit 3.3 of the Registrant's Registration Statement on Form S-1, Registration No. 33-69102). |
| 4.1 | Indenture agreement dated as of June 15, 1994 for $100,000,000 of 9¼% Senior Subordinated Notes due 2004 between Louis Dreyfus Natural Gas Corp., as Issuer, and Bank of Montreal Trust Company, as Trustee (incorporated by reference to Exhibit 10.2 of the Registrant's Form 10-Q for the quarter ended September 30, 1994). |
| 4.2 | Indenture agreement dated as of December 11, 1997 for $200,000,000 of 6f% Senior Notes due 2007 between Louis Dreyfus Natural Gas Corp. and LaSalle National Bank as Trustee (incorporated by reference to Exhibit 4.1 of the Registrant's Registration Statement on Form S-4, Registration No. 333-45773). |
| *10.1 | Stock Option Plan of Louis Dreyfus Natural Gas Corp. as amended and restated effective December 1998 (incorporated by reference to Exhibit 10.1 of the Registrant's Form 10-K for the fiscal year ended December 31, 1998). |
| 10.2 | Form of Indemnification Agreement with directors of the Registrant (incorporated by reference to Exhibit 10.2 of the Registrant's Registration Statement on Form S-1, Registration No. 33-69102). |
| 10.3 | Registration Rights Agreement between the Registrant and Louis Dreyfus Natural Gas Holdings Corp. (incorporated by reference to Exhibit 10.3 of the Registrant's Registration Statement on Form S-1, Registration No. 33-76828). |
| 10.4 | Amendment dated December 22, 1993 to Registration Rights Agreement between the Registrant, Louis Dreyfus Natural Gas Holdings Corp. and S.A. Louis Dreyfus et Cie (incorporated by reference to Exhibit 10.4 of the Registrant's Registration Statement on Form S-1, Registration No. 33-76828). |
| 10.5 | Services Agreement between the Registrant and Louis Dreyfus Holding Company, Inc. (incorporated by reference to Exhibit 10.5 of the Registrant's Registration Statement Form S-1, Registration No. 33-76828). |
| 10.6 | Credit Agreement dated as of October 14, 1997, among Louis Dreyfus Natural Gas Corp., as Borrower, Bank of Montreal, as Administrative Agent, Chase Manhattan Bank, as Syndication Agent, NationsBank of Texas, N.A., as Documentation Agent, and certain other lenders signatory thereto (incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K dated October 14, 1997). |
| *10.7 | Amendment to Option Agreement of Simon B. Rich, Jr. (incorporated by reference to Exhibit 10.14 of the Registrant's Form 10-K for the fiscal year ended December 31, 1996). |
| *10.8 | Form of Amendment to Outstanding Option Agreements of Employees (incorporated by reference to Exhibit 10.15 of the Registrant's Form 10-K for the fiscal year ended December 31, 1996). |
| *10.9 | Form of Amendment to Outstanding Option Agreements of Non-Employee Directors (incorporated by reference to Exhibit 10.16 of the Registrant's Form 10-K for the fiscal year ended December 31, 1996). |
| *10.10 | Employment Agreement, dated as of June 24, 1997, between Louis Dreyfus Natural Gas Corp. and Mark Andrews (incorporated by reference to Exhibit 10.3 to Form 8-K dated June 24, 1997, of American Exploration Company). |

*10.11 Form of Change in Control Agreements between Registrant and Messrs. Mark E. Monroe, Jeffrey A. Bonney, Richard E. Bross, Ronnie K. Irani and Kevin R. White (incorporated by reference to Exhibit 10.1 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.12 Louis Dreyfus Natural Gas Corp. Deferred Stock Trust Agreement dated April 14, 1998 (incorporated by reference to Exhibit 10.2 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.13 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Mark E. Monroe (incorporated by reference to Exhibit 10.3 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.14 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Richard E. Bross (incorporated by reference to Exhibit 10.4 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.15 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Ronnie K. Irani (incorporated by reference to Exhibit 10.5 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.16 Deferred Stock Award Agreement dated March 31, 1998 between Registrant and Kevin R. White (incorporated by reference to Exhibit 10.6 of the Registrant's Form 10-Q for the quarter ended March 31, 1998).

*10.17 Louis Dreyfus Natural Gas Corp. Non-employee Director Deferred Stock Trust Agreement dated December 1, 1998 (incorporated by reference to Exhibit 10.18 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

*10.18 Amendment No. 1 to Louis Dreyfus Natural Gas Corp. Deferred Stock Trust Agreement dated September 30, 1998 (incorporated by reference to Exhibit 10.19 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

*10.19 Louis Dreyfus Natural Gas Corp. Non-Employee Director Deferred Stock Compensation Program as adopted effective July 23, 1998 (incorporated by reference to Exhibit 10.20 of the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

*10.20 Louis Dreyfus Natural Gas Corp. 2000 Employee Stock Purchase Plan dated May 16, 2000 (incorporated by reference to the Registrant's Registration Statement on Form S-8, Registration No. 333-37490).

21.1 List of subsidiaries of the Registrant.

23.1 Consent of Independent Auditors.

24.1 Powers of Attorney.

Exhibit 21.1

List of Subsidiaries of the Registrant

Louis Dreyfus Gas Marketing Corp.
LDNG Acquisition, Inc.
LDNG Texas Holdings, Inc.
LDNGC Series 1998-A Trust
Louis Dreyfus Natural Gas I, L.P.
Stonewater Pipeline Company of Texas, Inc.
Stonewater Pipeline Company, L.P.
American Exploration Production Company
American Reserves Corporation

Exhibit 23.1

**Consent of Independent Auditors**

We consent to the incorporation by reference in the Registration Statements (Form S-8, No. 33-92724, No. 333-29907 and No. 333-82057) pertaining to the Louis Dreyfus Natural Gas Corp. Stock Option Plan, the Registration Statement (Form S-8, No. 333-77185) pertaining to the Louis Dreyfus Natural Gas Corp. Non-Employee Director Deferred Compensation Program, the Registration Statement (Form S-3 No. 333-21321) and the Registration Statement (Form S-8, No. 333-37490) pertaining to the Louis Dreyfus Natural Gas Corp. 2000 Employee Stock Purchase Plan and related Prospectuses of our report dated February 5, 2001, with respect to the consolidated financial statements and schedule of Louis Dreyfus Natural Gas Corp. included in the Annual Report on Form 10-K for the year ended December 31, 2000.

ERNST & YOUNG LLP

Oklahoma City, Oklahoma
February 27, 2001

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Simon B. Rich, Jr. | Chairman of the Board of Directors |

Simon B. Rich, Jr.
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Mark E. Monroe | Director |

Mark E. Monroe
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Richard E. Bross | Director |

Richard E. Bross
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Gerard Louis-Dreyfus | Director |

Gerard Louis-Dreyfus
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
| --- | --- |
| /s/ Daniel R. Finn, Jr. | Director |

Daniel R. Finn, Jr.
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Peter G. Gerry | Director |

Peter G. Gerry
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ John H. Moore | Director |

John H. Moore
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ James R. Paul | Director |

James R. Paul
(Please print name)

# POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Mark Andrews | Vice Chairman of the Board of Directors |

Mark Andrews
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ E. William Barnett | Director |

E. William Barnett
(Please print name)

POWER OF ATTORNEY

KNOW ALL BY THESE PRESENTS, that the undersigned hereby constitutes and appoints Jeffrey A. Bonney, Mark E. Monroe and Kevin R. White, and each or any of them, his true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities to sign the Form 10-K for the year ended December 31, 2000 of Louis Dreyfus Natural Gas Corp. and any and all amendments thereto and to file the same with exhibits thereto and other documents in connection therewith with the Securities and Exchange Commission, granting unto each said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

DATED this 27th day of February, 2001.

| Signature | Title |
| --- | --- |
| /s/ Nancy K. Quinn | Director |

Nancy K. Quinn
(Please print name)

POWER OF ATTORNEY

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DATED this 27th day of February, 2001.

| Signature | Title |
|---|---|
| /s/ Ernest F. Steiner | Director |

Ernest F. Steiner
(Please print name)